

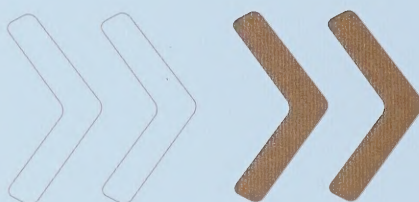


focus forward

annual
report
2008

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Operational highlights

(Year ended December 31)

	2008	2007	% Change
Oil and Gas Production			
Daily production oil equivalent from continuing operations (boed) ⁽¹⁾ (3)	27,683	26,509	4
Percent daily production natural gas	51%	58%	(12)
Average realized price from continuing operations (before realized financial derivative instruments)			
Crude oil blend (\$/bbl)	\$ 82.79	\$ 56.74	46
Natural gas liquids (\$/bbl)	\$ 76.88	\$ 55.07	40
Natural gas (\$/mcf)	\$ 8.23	\$ 6.42	28
Oil equivalent (\$/boe) ⁽¹⁾	\$ 65.64	\$ 46.09	42
Field netback from continuing operations (before realized financial derivative instruments) (\$/boe)	\$ 39.85	\$ 25.47	56
Field netback from continuing operations (including realized financial derivative instruments) (\$/boe)	\$ 38.75	\$ 25.65	51
Total proved plus probable reserves (mmboe)	98	101	(3)
Total proved plus probable reserve life index (years)	10.0	9.7	3
Provident Midstream			
Provident Midstream NGL sales volumes (bpd)	119,649	120,785	(1)
EBITDA (000s) ⁽²⁾	\$ 212,761	\$ 225,675	(6)

⁽¹⁾ Provident reports oil equivalent production converting natural gas to oil on a 6:1 basis. ⁽²⁾ EBITDA is earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items. See "Reconciliation of non-GAAP measures". ⁽³⁾ Effective in the first quarter of 2008, Provident's USOGP business is accounted for as discontinued operations (see note 15 of consolidated financial statements).

focused on long-term value

Financial highlights

(Year ended December 31) (\$000s except per unit data)

	2008	2007	%Change
Revenue (net of royalties and financial derivative instruments)	\$ 3,239,163	\$ 2,038,515	59
Funds flow from Provident Upstream operations ⁽¹⁾	\$ 338,640	\$ 204,252	66
Funds flow from Provident Midstream operations ⁽¹⁾	\$ 178,982	\$ 178,432	-
Funds flow from continuing operations ^{(1) (2)}	\$ 517,622	\$ 382,684	35
Total funds flow from operations ⁽¹⁾	\$ 655,157	\$ 468,255	40
Per weighted average unit – basic and diluted ⁽³⁾	\$ 2.57	\$ 2.04	26
Distributions to unitholders	\$ 352,291	\$ 333,352	6
Per unit	\$ 1.38	\$ 1.44	(4)
Percent of funds flow from operations paid out as declared distributions ⁽⁴⁾	58%	77%	(25)
Net income	\$ 157,392	\$ 30,434	417
Per weighted average unit – basic and diluted ⁽³⁾	\$ 0.62	\$ 0.13	377
Capital expenditures Provident Upstream operations	\$ 209,147	\$ 146,209	43
Capital expenditures Provident Midstream operations	\$ 37,800	\$ 31,904	18
Capital expenditures (continuing operations)	\$ 246,947	\$ 178,113	39
Oil and gas property acquisitions, net (continuing operations)	\$ 24,181	\$ 13,050	85
Proceeds on sale of discontinued operations, net of tax	\$ 457,906	\$ -	
Weighted average trust units outstanding (000s) -basic and diluted ⁽³⁾	255,177	229,939	11
Long-term debt (including current portion) ⁽⁵⁾	\$ 765,679	\$ 1,199,634	(36)
Unitholders' equity	\$ 1,636,347	\$ 1,708,665	(4)

⁽¹⁾ Represents cash flow from operations before changes in working capital and site restoration expenditures. ⁽²⁾ Effective in the first quarter of 2008, Provident's USOGP business is accounted for as discontinued operations (see note 15 of consolidated financial statements). ⁽³⁾ Includes dilutive impact of unit options and convertible debentures. ⁽⁴⁾ Calculated as distributions to unitholders divided by funds flow from operations less distributions to non-controlling interests of \$51.4 million (2007 - \$35.8 million). ⁽⁵⁾ Continuing operations.



Letter to Unitholders



Provident's 65,000 bpd Redwater fractionation facility

"Providing for the Future" was our message to investors in 2001, our first year operating as an income trust. Our strategy was to create a portfolio of energy assets that could provide stable cash flow and distributions to unitholders while protecting capital investment. Through our investments in North American upstream and midstream assets, Provident created a quality energy portfolio that provides a balanced risk profile and has generated a relatively stable monthly income stream for investors.

Following record commodity prices throughout most of 2008, the unprecedented decline in the global capital and commodity markets late in the year has created short-term challenges for all energy companies to access new investment capital in order to support growth and generate cash flow comparable to historical levels. Our management team and the board of directors are committed to positioning Provident to maintain our flexibility and to exploit new opportunities as they arise. We have a strong balance sheet and numerous high impact opportunities in both our midstream and upstream business units to pursue. Our priority for 2009 is to protect and add value to Provident's core businesses by selectively developing high return opportunities that contribute to the long-term health and success of Provident.

During 2008, the Trust executed its plan to deliver consistent operational performance, despite unpredictable market conditions, and made progress towards reaching its strategic objectives. Total funds flow from operations increased 40 percent to approximately \$655 million, of which \$352 million was distributed to our unitholders, resulting in a payout ratio of 58 percent for the year. This strong cash flow coupled with our U.S. divestiture enabled Provident to reduce Canadian bank debt by 45 percent to \$505 million by year end. Provident has improved its financial flexibility while it continues to operate and develop its world class energy assets.

As an executive team, our major strategic goal for last year was to enhance the flexibility of Provident's organizational structure in order to better position the organization beyond 2011, at which time the new tax on trust distributions will be implemented. Following a full review of our structural options we determined that in order to allow for optimal flexibility, we needed to monetize the gains



Funds Flow from Operations Per Unit

Since 2004, funds flow from operations per unit has increased at a compound annual rate of 10 percent

from our investment in the U.S. E&P business before we could reorganize our Canadian businesses. In June and August of 2008, Provident successfully concluded the complex sale of our equity interest in BreitBurn Energy Partners, L.P., BreitBurn GP LLC and BreitBurn Energy Company L.P., for aggregate after tax proceeds of \$458 million which were used to repay long-term debt. As a result, Provident exited 2008 with excellent financial flexibility having drawn approximately \$505 million against its \$1.125 billion credit facility. In October of 2008, Provident also completed an internal reorganization of legal entities within our structure to facilitate the eventual separation of our upstream and midstream business units.

Operations Review: Sharpening Our Focus

Provident Upstream

Provident's upstream oil and gas division had an exceptional year generating record funds flow from operations of \$339 million in 2008 and reaching all guidance targets. Average daily production volumes grew by four percent in 2008 to approximately 27,700 barrels of oil equivalent per day (boed) while reserve life remained stable at 10 years. This stability was achieved in part, through the development of internally generated opportunities. As we position Provident for growth beyond 2011 we recognize the need to move toward adding more internal growth opportunities through full-cycle development. The shift to full-cycle growth commenced over the past couple of years and in 2008 we spent approximately 30 percent of our capital budget on land and facilities resulting in significantly higher FD&A costs than in prior years. This included substantial land purchases in Northwest Alberta to expand the scope of our Pekisko play as well as facilities in Northwest Alberta and Dixonville. As we add substantial reserves and production in these areas in future years we expect our F&D costs to return to more competitive levels.

Provident continues to add growth opportunities from within its portfolio, most notably the emerging Pekisko opportunity. Over the past two years, our upstream business unit has undertaken efforts to prove up this early stage opportunity. Offsetting our existing operations in the core area of Northwest Alberta, the play covers an extensive exploration trend which Provident believes contains significant medium gravity sweet crude oil. Provident holds 61,000 net acres (95 sections) of



Payout Ratio

The Trust's payout ratio in 2008 was 58 percent, the strongest payout ratio to date



Consolidated Total Debt (\$ millions) and Consolidated Total Debt to Funds Flow from Operations ⁽²⁾

Consolidated total debt was reduced by approximately 50 percent in 2008

⁽¹⁾Includes debt from continuing operations of \$1,200 million and debt from discontinued operations of \$349 million.

⁽²⁾The ratio of consolidated long term debt to funds flow from operations. 2008 excludes funds flow from discontinued operations to reflect the U.S. disposition.



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undeveloped land along the play. In 2008, Provident spent approximately \$47.5 million on the Pekisko play including land acquisition, a geological and seismic study and the drilling of two exploratory wells.

Provident's independent reserve evaluator has assigned approximately 2.7 million barrels of total proved plus probable oil reserves to these two wells and their offset locations for 2008. During the 2009 winter drilling program, the Trust drilled three additional Pekisko wells with encouraging initial geological results, and began pipeline construction and surface facility installation that will enable year-round oil production. The surface infrastructure is scheduled to be complete by the end of the first quarter, at which time four of the five Pekisko wells will be brought on year-round production, with the fifth remaining on seasonal winter production. With approximately 330 potential drilling locations identified, we remain optimistic that this high impact opportunity has the potential to add significant long-term value to Provident's upstream business.

The key drivers for Provident Upstream in 2009 are crude oil and natural gas prices, access to and cost of equity and debt capital, foreign exchange rates between the Canadian and U.S. dollar and the operating costs associated with oil and natural gas exploration and production. Although the Trust's upstream business unit has an extensive portfolio of drilling opportunities and prospective plays, Provident is focusing spending on long-term, high return projects while ensuring capital efficiency.

Provident's upstream business unit has a capital budget for 2009 of \$88 million. This was revised in February 2009 from an original budget of \$125 million to align capital spending with current economic conditions. Approximately \$36 million has been directed towards the development of the prospective Pekisko opportunity. Additionally, \$19 million is planned for the Dixonville area to implement the first phase of the water flood for enhanced recovery of Montney "C" crude oil. Incremental production is expected to be added upon completion of all three phases of the water flood program beyond 2009. The remainder of the capital budget will be directed towards drilling and optimization activities in our remaining core areas.

As we announced in February, Provident Upstream expects 2009 production to average between 23,500 and 25,000 barrels of oil equivalent per day and remain relatively balanced between crude oil and natural gas. Natural production declines are expected to be partially offset by new production additions as capital spending has been curtailed and primarily focused on longer term, prospective projects. Operating costs will likely remain relatively stable in the first half of 2009, but should begin to moderate in the latter half of the year as labour, service and material costs deflate as development activity slows.

Provident Midstream

In 2008 the midstream business unit delivered \$213 million in earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items (EBITDA) marking its third consecutive year generating EBITDA in excess of \$200 million. Provident Midstream delivered this strong performance in 2008 despite a challenging latter half of the year. The final four months of 2008 were characterized by a declining NGL (ethane, propane, butane and condensate) price environment, high inventory costs, a narrowing frac spread ratio (the relationship between crude oil and natural gas prices), and a significant reduction in feedstock demand from the petro-chemical industry as a result of the economic downturn and tight credit markets. Demand has since returned to more typical levels early in the first quarter of 2009. Provident's focus on operational excellence resulted in a safe, complete turnaround at our Empress facility in October to improve operating efficiency, and the successful first phase of a multi-year debottlenecking initiative at our Redwater facility.



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1. Northwest Alberta - Rainbow Lake
2. West Central Alberta - Wildcat Hills
3. Lloydminster

Provident's midstream business unit has a sizeable portfolio of opportunities and benefits from a flexible capital profile. The Trust is able to adjust the level of capital investment to reflect prevailing market conditions. Provident's new, efficient and low cost facilities require low sustaining capital of only \$6 million for 2009. Key drivers for the business include access to and input costs of NGL and natural gas feedstocks, power, and the demand for our finished products including ethane, butane, propane and condensate. During the first quarter of 2009, NGL margins have strengthened when compared with the fourth quarter of 2008. This is due to the depletion of the majority of the high cost inventory accumulated during 2008 coupled with strong winter demand resulting in higher realized prices for propane and butane.

Provident Midstream has a total capital budget of approximately \$27 million for 2009. This budget will be used, in part, to complete two 500,000 bpd condensate caverns which will be put into service at Redwater in the summer of 2009. Work continues on a third condensate cavern of equal size with drilling now complete and washing underway. This cavern is expected to enter service in 2011 and will provide diluent storage capacity for oil sands producers. Upon completion of these caverns, Provident will own approximately 6.6 million barrels of underground product storage at Redwater. Provident is also allocating a portion of its 2009 capital budget towards the initial phases of a depropanizer project. The facility would be strategically located with access to the premium NGL markets in the Michigan area. The remainder of the 2009 capital budget will be used in certain facility optimization and debottlenecking initiatives as well as for normal course facility maintenance at Redwater, Empress and Sarnia.

2009 Outlook: Looking Forward

In 2008 Provident initiated a review of the overall structure and strategic direction of the Trust, in part to prepare for the Government of Canada's decision to impose a SIFT tax on income trusts effective January 2011. This review process was also undertaken with the intent to optimize business performance, facilitate growth, improve the cost of capital, and ensure the Trust is being accorded the appropriate value for its component businesses. Although we made some great strides towards these goals commencing with the sale of our U.S. E & P business, the impact of the current economic downturn has created additional challenges. Despite this increase in complexity Provident continues to assess structural options while focusing on business fundamentals and capitalizing on high-return growth opportunities.

As a management team, we plan to continue to execute the best possible opportunities while recessionary challenges in the global economy run their course. We will also continue to carefully allocate cash flow to capital programs, unitholder distributions and long-term debt to ensure that Provident is functioning largely in a self-sufficient manner by operating and growing within our cash flow and, if necessary, from existing credit facilities.

I want to acknowledge the hard work and dedication of all our employees and the valued guidance provided by our board members in 2008. Our intention for 2009 and beyond is to develop and operate safe, responsible energy operations that will deliver sustainable long-term value to unitholders.



Thomas W. Buchanan
President and Chief Executive Officer



Provident Upstream



Northwest Alberta winter drilling operations



Funds Flow from Operations (\$ millions)

Since 2004, funds flow from Canadian upstream operations has increased at a compound annual rate of 23 percent

MOVING FORWARD

Provident Upstream provides an opportunity to participate in a large scale oil and gas investment characterized by a low risk, cash generating asset portfolio focused on sustainability with high impact organic growth potential.

Provident Upstream produces oil and natural gas across seven areas in Alberta and southern Saskatchewan and is made up of skilled, area focused, multi-disciplined asset teams. Provident produces a balanced profile of crude oil and natural gas. Provident's upstream assets are stable, low-risk producing properties. Natural production declines are partially offset by exploiting a multi-year inventory of approximately 1,500 opportunities over 15 different play types. This portfolio of opportunities reflects Provident's transition to more full cycle internal development. The Provident Upstream team has succeeded in strengthening the asset mix considerably over time and in optimizing the results from those assets.

2008 Capital Program	\$ million ⁽¹⁾	Wells ⁽²⁾⁽³⁾
Northwest Alberta	\$ 79	14.0
Dixonville	\$ 60	41.0
Southeast Saskatchewan	\$ 21	13.8
Other	\$ 49	18.6
Provident Upstream	\$ 209	87.4

(1) Does not include property acquisitions

(2) Provident Upstream had a success rate in 2008 of approximately 99%

(3) Net wells drilled, excluding recompletions and workovers

2009 Guidance

Capital Budget \$88 million

Number of wells 23.8 (net)

Production 23,500 to 25,000 boed

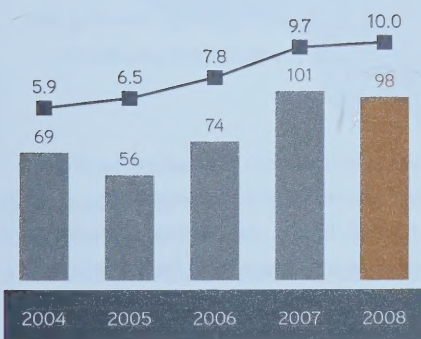


Dixonville Waterflood Dixonville Alberta

Provident's Dixonville core area is well situated to realize medium and longer term benefits by employing enhanced recovery technology. Provident plans to implement a three phase field-wide water flood program utilizing horizontal production and injection wells. With original oil in place estimated at 228 MMbbl on Provident lands, reservoir modeling suggests that a water flood program has the potential to yield a recovery between 15 and 20 percent (from 12 percent primary recovery) from the Montney "C" oil pool. Results to date have been promising with pilot water injector wells demonstrating incremental oil recovery in offsetting producers. Subsequent production additions are expected to be added upon completion of the waterflood in 2010 and beyond.

Pekisko Oil Play Northwest Alberta

Provident's early stage Pekisko oil play has been a focus of Provident Upstream during the last two years. This internally generated, high-impact grass roots oil play has the potential to add significant reserves and production to Provident's portfolio.



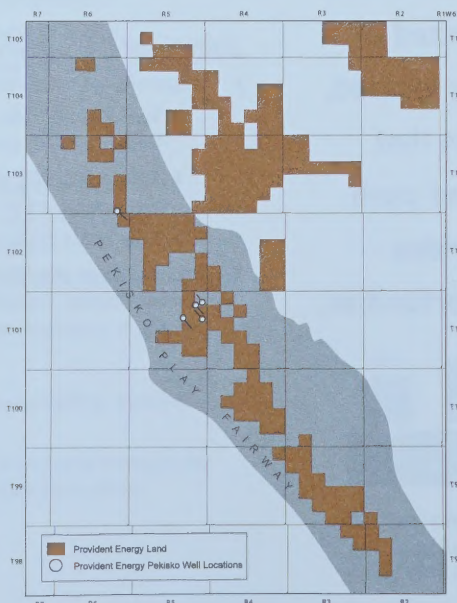
Total Proved Plus Probable Reserves (MMboe)
& Reserve Life Index (yrs)

Over the past five years Provident has focused on acquiring and developing quality assets with growth potential



Production (boed)

Provident has focused on sustainability, replacing production through acquisitions and internal development



- > 5 horizontal wells
- > Multi-stage frac
- > 2.7 MMboe 2P reserves
- > 95 sections (61,000 acres) net land position
- > Approximately 330 identified drilling locations
- > Surface infrastructure to enable year-round production



Provident Midstream



One of Provident's extraction facilities at Empress

CLEAR FOCUS

Provident Midstream provides an opportunity to participate in a world class midstream investment characterized by a low risk, strategically located, integrated value chain that generates a diversified cash flow stream and provides excellent upside opportunities.

Provident Midstream is an integrated NGL and commercial services business that owns and operates world class extraction, gathering, transportation, storage, fractionation and marketing facilities in Canada's Western Canadian Sedimentary Basin. Provident's Midstream NGL operations and facilities extend eastward from northwest British Columbia to Sarnia, Ontario and Lynchburg, Virginia. Physical facilities are enhanced by Provident Midstream's marketing and logistics group with offices located in Calgary, Sarnia and Houston, Texas. Provident Midstream serves Alberta's growing oil sands industry by providing storage, blending, and rail and pipeline terminalling service to oil sands producers and processors.

Growth Opportunities

Provident Midstream has identified over \$300 million in planned capital projects and an additional \$300 million of risked opportunities for future growth and expansion. Provident Midstream benefits from a scalable capital profile that allows incremental growth and expansion on projects ranging from \$1 million to \$100 million in capital investment in any particular year depending on market conditions.

2009 Capital Program

- > Expansion of condensate and other products storage at Redwater
 - > Two 500,000 bbl underground condensate caverns are underway at Redwater with completion expected in 2009
 - > A third 500,000 bbl condensate cavern at Redwater will be completed and contracted in 2011
 - > Total of 6.6 MMbbl cavern storage once complete
- > Initial phases of a Michigan depropanizer project that would extract propane, for sale locally, from NGL delivered off the Enbridge Pipeline System with access to premium markets in the Michigan area



Business Lines

Redwater West

- > Purchases NGL mix from various producers and fractionates into finished products
- > Generates revenues through extraction, gathering, transportation, storage and fractionation of NGL to produce specific products
- > Competitive advantages include the ability to process sour NGL
- > One of only two fractionation facilities in Fort Saskatchewan capable of processing ethane plus

Empress East

- > Extracts NGLs from natural gas at the Empress straddle plants
- > Generates revenue through the sale of finished products into markets in Western & Central Canada and the Eastern United States
- > Provident's Empress NGL extraction facilities are amongst the most modern and efficient facilities in the Empress complex

Commercial Services

- > Contracts related to third-party fractionation, storage, loading, pipeline transportation and marketing services
- > Generates revenue through fee-for-service income primarily through the utilization of Provident's Redwater West and Empress East assets



EBITDA (\$ millions)

EBITDA has exceeded \$200 million for each of the past three years



Corporate Governance



Provident's Empress debutanizer

For information on **Environment, Health & Safety**, and **Corporate Responsibility**, please visit our website at www.providentenergy.com/resp/environment/environmentoverview.cfm.

For information on **Community Investment**, please visit our website at www.providentenergy.com/resp/community/communityoverview.cfm.

Board of Directors and Governance Systems

At Provident, the values of respect, integrity, creativity and excellence ("RICE") provide the foundation on which our corporate governance practices were developed. Provident is committed to the principles of good governance, and the Trust employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors is responsible for the stewardship of Provident by overseeing the management of the business and affairs of Provident with the goal of providing long-term unitholder value. The Board will discharge its responsibilities directly and through its standing committees, consisting of an Audit Committee, Governance, Human Resources and Compensation Committee, Reserves, Operations and Environmental, Health & Safety Committee.

The Board of Directors has developed and implemented corporate governance practices to ensure it has the authority, expertise, systems and processes to review and evaluate Provident's strategic direction, business risks, financial and operational performance, internal controls, communication strategy and executive performance.

As a Canadian trust listed on the New York Stock Exchange ("NYSE"), Provident is not required to comply with most of the NYSE corporate governance standards, so long as it complies with the Canadian corporate governance practices. In order to claim such an exemption, however, Provident must disclose the significant difference between its corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE corporate governance standards. Provident's Statement of Significant Governance Differences can be found on Provident's website at www.providentenergy.com.

Oil and Natural Gas Reserves

Provident's reserves were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel) and by AJM Petroleum Consultants (AJM) in accordance with the Canadian Securities Administrators' National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI 51-101). McDaniel evaluated all of Provident's Canadian oil and natural gas properties, except the Northwest Alberta properties which were evaluated by AJM. McDaniel and AJM are independent qualified reserves evaluators appointed pursuant to NI 51-101. Additional information pertaining to NI 51-101 and some of the key reserves definitions are provided at the conclusion of the Reserves section. Additional details on the Trust's reserves can be found in Form NI 51-101 F1.

On June 17, 2008 Provident announced that it had sold a portion of its U.S. oil and gas business consisting of its 22 percent interest in BreitBurn Energy Partners L.P. ("BreitBurn MLP") and its 96 percent interest in BreitBurn GP LLC ("BreitBurn GP"). On July 30, 2008 Provident announced that it had reached an agreement to sell the remaining portion of its U.S. oil and gas business, BreitBurn Energy Company L.P. ("BreitBurn"). Provident subsequently announced the close of the sale of BreitBurn on August 26, 2008. After the transactions all of Provident's reserves are located in Canada.

Provident's oil and natural gas reserves and present value of estimated future cash flows based on forecast prices and costs as of December 31, 2008 using the McDaniel January 1, 2009 price forecast are summarized in the following tables. Reserves are presented on a Gross (working interest) and Net basis (refer to the notes under the tables and to the Definitions at the end of the Reserves section for explanations of company share, working interest, gross and net). In October 2007, the Alberta government announced its intention to amend crown royalties effective January 1, 2009. Provident Upstream (COGP) reserves as presented herein are based on the Alberta New Royalty Framework including the Transitional Royalties that were announced in November 2008.

Reserves as of December 31, 2008^(a)

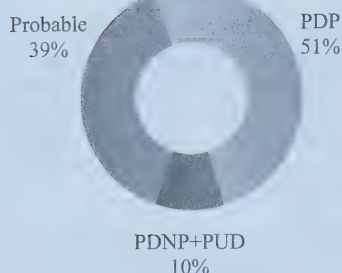
Using McDaniel Price Forecast

	Gross Reserves ^(b)						Net Reserves ^(c)					
	Light & Medium Crude Oil ^(d)	Heavy Crude Oil ^(d)	Total Oil	NGL	Natural Gas	Total Boe	Light & Medium Crude Oil	Heavy Crude Oil	Total Oil	NGL	Natural Gas	Total Boe
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(Mboe)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(Mboe)
Proved Reserves												
Producing	18,075	3,754	21,829	1,994	154,455	49,565	13,934	3,122	17,056	1,402	130,200	40,158
Non-Producing	199	195	394	108	17,392	3,400	143	164	307	72	11,743	2,336
Undeveloped	1,586	1,145	2,731	161	20,705	6,342	1,402	844	2,245	102	17,242	5,221
Total Proved	19,859	5,094	24,953	2,262	192,552	59,307	15,479	4,129	19,609	1,576	159,185	47,715
Probable	19,400	3,982	23,382	924	82,399	38,039	12,723	3,084	15,806	648	66,915	27,607
Total Proved plus Probable	39,259	9,076	48,335	3,186	274,951	97,346	28,202	7,213	35,415	2,223	226,100	75,322

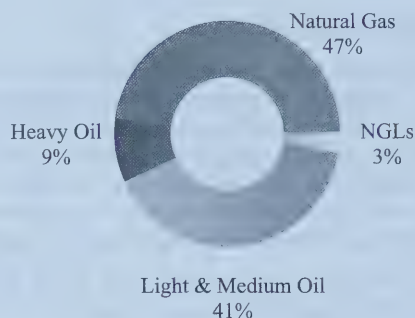
Notes:

- Tables may not add due to rounding.
- Gross Reserves are Provident's working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of Provident.
- Net Reserves are Provident's working interest (operated or non-operated) share after deduction of royalty obligations, plus Provident's royalty interests in reserves.
- The definition of light, medium and heavy oil for Canada is consistent with the royalty regime of each Province. Heavy Oil within the province of Alberta includes oil defined as heavy and ultra-heavy in accordance with the New Royalty Framework, which came into effect on January 1, 2009.

Reserves by Category



P+P Reserves by Product

**Present Value of Reserves as of December 31, 2008^(a)****Using McDaniel Price Forecast**

The present value of estimated future cash flows based on forecast prices and costs of Provident's oil and natural gas reserves are summarized in the following tables. The impact of Federal income tax changes that were enacted during 2007 have been incorporated in the table showing After Tax values. According to these tax laws the Trust is expected to be taxable beginning January 1, 2011. Tax pools held by the Trust will defer the impact of these changes such that only the values of total proved and proved plus probable reserves will be affected.

Present Value (\$000's) Before Tax Discounted at					
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	\$ 1,422,130	\$ 1,019,045	\$ 951,406	\$ 817,979	\$ 720,111
Non-Producing	53,423	46,336	42,713	34,967	29,138
Undeveloped	107,880	44,420	34,440	15,380	2,119
Total Proved	1,583,434	1,109,801	1,028,558	868,325	751,368
Probable	1,463,803	577,184	492,757	355,425	273,576
Total Proved plus					
Probable	\$ 3,047,237	\$ 1,686,985	\$ 1,521,315	\$ 1,223,751	\$ 1,024,943

Present Value (\$000's) After Tax ^(b) Discounted at					
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	\$ 1,422,130	\$ 1,019,045	\$ 951,406	\$ 817,979	\$ 720,111
Non-Producing	53,423	46,336	42,713	34,967	29,138
Undeveloped	99,727	42,459	33,040	14,759	1,833
Total Proved	1,575,281	1,107,840	1,027,159	867,705	751,082
Probable	1,135,835	466,976	403,727	300,068	237,062
Total Proved plus					
Probable	\$ 2,711,116	\$ 1,574,815	\$ 1,430,886	\$ 1,167,773	\$ 988,144

Notes:

(a) Tables may not add due to rounding.

(b) After tax values include the impact of Canadian Federal and Provincial Income taxes beginning January 1, 2011.

COGP Oil and Natural Gas Reserves

Total COGP proved plus probable reserves decreased from 101,239 Mboe as of December 31, 2007 to 97,763 Mboe as of December 31, 2008. After accounting for production, COGP total proved reserves increased by 4,858 Mboe while proved plus probable reserves increased by 6,657 Mboe. Internal development activities in Western Canada were successful in replacing 70 percent of production. Drilling additions include 1,361 Mboe total proved and 2,695 Mboe proved plus probable reserves for the emerging Pekisko oil play in Northwest Alberta. Acquisitions of partner interests in Southeast Saskatchewan plus various smaller acquisitions added proved plus probable reserves of 1,047 Mboe. Drilling and tie-in activity, which was primarily focused in the Dixonville and Rainbow areas of Alberta and the Steelman area of Southeast Saskatchewan, resulted in the transfer of 3,684 Mboe to proved developed producing and 1,081 Mboe from probable to proved.

COGP Reconciliation Summary^(a) Proved Developed Producing

Company Share (WI +RI) ^(b)	Light & Medium Crude Oil ^(d) Mbbl	Heavy Crude Oil ^(d) Mbbl	Total Crude Oil Mbbl	Gas MMcf	NGL Mbbl	Total Boe Mboe
Balance at December 31, 2007^(d)	16,589	3,608	20,198	173,267	2,247	51,323
Production	(3,724)	(841)	(4,565)	(30,758)	(440)	(10,132)
Drilling Activity						
Exploration Discoveries	0	0	0	0	0	0
Drilling Extensions	349	462	811	2,530	14	1,246
Recompletion	241	741	982	4,652	22	1,779
Transfer	3,049	189	3,237	2,651	5	3,684
Acquisition	445	0	445	266	1	490
Divestiture	0	0	0	0	0	0
Economic Factors	16	3	19	1,862	10	339
Technical Revisions	1,153	(404)	749	1,044	161	1,084
Balance at December 31, 2008	18,117	3,759	21,875	155,514	2,019	49,813
WI Share^(e)						
Balance at December 31, 2008	18,075	3,754	21,829	154,455	1,994	49,565

COGP Reconciliation Summary^(a)**Total Proved**

	Light & Medium Crude Oil ^(d)	Heavy Crude Oil ^(d)	Total Crude Oil	Gas	NGL	Total Boe
Company Share (WI +RI)^(b)	Mbbl	Mbbl	Mbbl	MMcf	Mbbl	Mboe
Balance at December 31, 2007	22,896	4,412	27,308	210,879	2,415	64,869
Production	(3,724)	(841)	(4,565)	(30,758)	(440)	(10,132)
Drilling Activity						
Exploration Discoveries	0	0	0	0	0	0
Drilling Extensions	366	1,362	1,728	5,527	65	2,714
Recompletion	261	741	1,002	5,430	36	1,943
Transfer	914	68	982	589	0	1,081
Acquisition	662	0	662	277	1	709
Divestiture	0	0	0	0	0	0
Economic Factors	16	3	19	2,090	11	378
Technical Revisions	(1,486)	(646)	(2,132)	(240)	207	(1,965)
Balance at December 31, 2008	19,905	5,099	25,004	193,792	2,293	59,596
WI Share^(c)						
Balance at December 31, 2008	19,859	5,094	24,953	192,552	2,262	59,307

COGP Reconciliation Summary^(a)**Total Proved plus Probable**

	Light & Medium Crude Oil ^(d)	Heavy Crude Oil ^(d)	Total Crude Oil	Gas	NGL	Total Boe
Company Share (WI +RI)^(b)	Mbbl	Mbbl	Mbbl	MMcf	Mbbl	Mboe
Balance at December 31, 2007	42,007	7,133	49,140	292,763	3,305	101,239
Production	(3,724)	(841)	(4,565)	(30,758)	(440)	(10,132)
Drilling Activity						
Exploration Discoveries	0	0	0	0	0	0
Drilling Extensions	586	2,695	3,281	7,884	96	4,691
Recompletion	345	981	1,326	5,993	57	2,382
Transfer	0	0	0	0	0	0
Acquisition	968	0	968	463	1	1,047
Divestiture	0	0	0	0	0	0
Economic Factors	26	4	30	2,854	16	522
Technical Revisions	(884)	(890)	(1,773)	(2,426)	194	(1,984)
Balance at December 31, 2008	39,324	9,083	48,407	276,771	3,228	97,763
WI Share^(c)						
Balance at December 31, 2008	39,259	9,076	48,335	274,951	3,186	97,346

Notes:

(a) Tables may not add due to rounding.

(b) Company share includes working interest (WI) and royalty interest (RI) volumes.

(c) WI share includes the Company's working interests only, and excludes volumes associated with royalties.

- (d) The definition of light, medium and heavy oil for Canada is consistent with the royalty regime of each Province. Heavy Oil within the province of Alberta includes oil defined as heavy and ultra-heavy in accordance with the New Royalty Framework, which came into effect on January 1, 2009.

On a Consolidated basis, Proved plus Probable reserves decreased from 322,827 Mboe as of December 31, 2007 to 97,763 Mboe as of December 31, 2008. The majority of this decrease is due to the sale of the U.S. assets. Reconciliation tables that provide the details of Provident's consolidated reserve activity for each reserve category for the year ended December 31, 2008 are provided in Form 51-101 F1.

Price Forecast Summary

The following table summarizes the McDaniel January 1, 2009 price forecast used in evaluating Provident's reserves under forecast price and cost assumptions.

Year	Exchange Rate US\$/Cdn\$	WTI Crude at Cushing Oklahoma US\$/bbl	Light, Sweet Crude at Edmonton Cdn\$/bbl	Alberta Bow River Hardisty Cdn\$/bbl	Heavy Oil at Hardisty Cdn\$/bbl	Alberta AECO Gas Spot Price Cdn\$/MMbtu
2009	0.850	60.00	69.60	54.80	47.00	7.40
2010	0.850	71.40	83.00	65.30	56.10	8.00
2011	0.900	83.20	91.40	72.00	61.80	8.45
2012	0.950	90.20	93.90	73.90	64.00	8.80
2013	1.000	97.40	96.30	75.90	65.60	9.05

Reserve Life Index (RLI)

Provident's proved plus probable RLI as of December 31, 2008, which was stable at 10.0 years, was determined by applying the average actual production rates for the last quarter of 2008 to reserve volumes for each reserve category from the McDaniel and AJM evaluations as of December 31, 2008. The following table illustrates the reserve life index for COGP for the various product and reserve categories as of December 31, 2008 and for the prior five years.

COGP Reserve Life Index Company share (WI + RI)

Total Crude Oil	RLI (years) as of December 31					
	2008	2007	2006	2005	2004	2003
Proved Producing	4.9	4.6	4.4	3.9	3.3	3.0
Total Proved	5.6	6.2	4.8	4.3	4.0	3.9
Proved plus Probable	10.8	11.2	6.8	5.8	5.4	5.4

Natural Gas & NGL

Proved Producing	5.3	5.2	5.0	4.4	4.1	4.4
Total Proved	6.5	6.3	6.0	5.4	4.9	4.9
Proved plus Probable	9.3	8.7	8.3	7.1	6.4	6.1

Oil Equivalent (6:1)

Proved Producing	5.1	4.9	4.8	4.2	3.7	3.7
Total Proved	6.1	6.2	5.6	5.0	4.5	4.4
Proved plus Probable	10.0	9.7	7.8	6.5	5.9	5.7

Finding, Development and Acquisition Costs

Finding and development costs (F&D) include all costs to develop reserves, including land and seismic costs. The methodology used to calculate F&D costs under NI 51-101 requires that F&D costs incorporate changes in future development capital (FDC) required to bring non-producing and undeveloped reserves to production. This capital, which is included in the reserves evaluations, is part of the ongoing development process necessary to bring production on stream and generate cash flow. Provident's FDC has increased over the past several years with the acquisition of undeveloped reserves and with the 2008 addition of the emerging Pekisko oil play. To provide clarity in the true costs to find and develop reserves, Provident does not include the FDC associated with acquisitions in the F&D costs. However, since FDC is a component of the cost of acquiring reserves Provident does include the FDC associated with acquisitions in the FD&A costs.

Drilling and recompletion activity during 2008 made a significant contribution with total proved additions of 4,657 Mboe and proved plus probable additions of 7,073 Mboe. Provident's focus is development and exploitation of reserves and promotes between reserve categories. As a result of capital expenditures during 2008, Provident promoted 3,684 Mboe of reserves into the proved developed producing category. The associated capital and any changes to it have been included in the F&D calculations. Continued development of the Dixonville Montney C pool during 2008 was a significant recipient of capital expenditures resulting in transfers during 2008. Further development drilling and waterflood expansion of the Montney C pool is planned for the next several years.

The success of the Pekisko Oil play in 2008 led to proved reserve additions of 1,361 Mboe and proved plus probable additions of 2,695 Mboe for two producing Pekisko oil wells plus offsetting undeveloped locations. Expenditures for land and seismic activity associated with this play are included in the 2008 capital expenditures plus future development capital is included in the reserves for drilling, completion, facility and infrastructure costs.

The aggregate of the development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year. A three-year average of F&D costs is a better reflection of full cycle economics and is therefore a more appropriate view of the cost of reserve additions. The three-year average FD&A cost does include the change in FDC, including acquisitions, over the three year period. Acquisition costs include the cash cost of acquiring reserves and the fair value of liabilities assumed. NI 51-101 does not contemplate nor define acquisition costs. Provident has included goodwill on the corporate acquisitions as part of the purchase price allocation, and therefore forms part of the costs of acquiring the reserves.

Finding, development and acquisition (FD&A) costs including revisions and future development capital (FDC) were \$35.28 per boe of proved plus probable reserves in 2008 compared to \$23.31 per boe in 2007. The increase in 2008 FD&A costs reflect a bias towards long term capital spending in relation to full-cycle development activities with \$60 million (of \$231 million) invested in land, seismic and facilities that do not result in immediate reserve or production additions. COGP is building a long-term play for Pekisko Oil and investing in the long-term waterflood project at Dixonville. The three-year average FD&A costs including revisions and FDC were \$24.34 per boe of proved plus probable reserves in 2008.

Details of the F&D cost calculations and results are provided in the following tables.

The following table presents the details of the 2008 Finding, Development and Acquisition cost calculations and illustrates the impact of including the change in future development capital in the calculation.

COGP 2008 Finding, Development and Acquisition Costs

	Capital (\$000s)	Reserve Additions including Revisions Mboe ^(a)	F&D Costs \$/boe ^(b)
Finding and Development Costs			
<u>Total Proved</u>			
Capital Expenditures ⁽¹⁾	\$ 205,429	4,149	\$49.51
Change in FDC ⁽²⁾	(620)		
Total F&D including change in FDC	\$ 204,809	4,149	\$49.36
<u>Proved plus Probable</u>			
Capital Expenditures ⁽¹⁾	\$ 205,429	5,610	\$36.62
Change in FDC ⁽²⁾	(2,080)		
Total F&D including change in FDC	\$ 203,349	5,610	\$36.25
Finding, Development and Acquisition Costs			
<u>Total Proved</u>			
Capital Expenditures and Acquisition Costs ⁽¹⁾	\$ 231,161	4,858	\$47.58
Change in FDC ⁽²⁾	3,800		
Total FD&A including change in FDC	\$ 234,961	4,858	\$48.36
<u>Proved plus Probable</u>			
Capital Expenditures and Acquisition Costs ⁽¹⁾	\$ 231,161	6,657	\$34.73
Change in FDC ⁽²⁾	3,700		
Total FD&A including change in FDC	\$ 234,861	6,657	\$35.28

Details of Capital and FDC

(1) Total F&D Costs (\$000s)

2008 Oil and Gas Capital Expenditures	\$ 205,429
Property Acquisitions (net of dispositions)	25,732
Corporate Acquisitions	-
Total Oil and Gas FD&A costs	\$ 231,161

(2) Change in Future Development Costs (\$000s)

	Total Proved	Proved plus Probable
FDC as of 2008-12-31	\$ 165,400	\$ 221,800
FDC as of 2007-12-31	161,600	218,100
Change in FDC for FD&A Calculation	\$ 3,800	\$ 3,700
FDC of Acquired Properties	4,420	5,780
Change in FDC for F&D Calculation	\$ (620)	\$ (2,080)

The following table presents the details of the three-year average Finding, Development and Acquisition cost calculations and illustrates the impact of including the change in future development capital in the calculation.

COGP Three-year Finding, Development and Acquisition Costs

	Capital (\$000s)	Reserve Additions including Revisions Mboe ^(a)	F&D Costs \$/boe ^(b)
Finding and Development Costs			
Total Proved			
Capital Expenditures ⁽¹⁾	\$ 355,064	10,789	\$32.91
Change in FDC ⁽²⁾	(4,121)		
Total F&D including change in FDC	\$ 350,944	10,789	\$32.53
Proved plus Probable			
Capital Expenditures ⁽¹⁾	\$ 355,064	11,753	\$30.21
Change in FDC ⁽²⁾	(2,839)		
Total F&D including change in FDC	\$ 352,225	11,753	\$29.97
Finding, Development and Acquisition Costs			
Total Proved			
Capital Expenditures and Acquisition Costs ⁽¹⁾	\$ 1,523,076	45,528	\$33.45
Change in FDC ⁽²⁾	140,700		
Total FD&A including change in FDC	\$ 1,663,777	45,528	\$36.54
Proved plus Probable			
Capital Expenditures and Acquisition Costs ⁽¹⁾	\$ 1,523,076	70,269	\$21.68
Change in FDC ⁽²⁾	187,271		
Total FD&A including change in FDC	\$ 1,710,347	70,269	\$24.34

Details of Capital and FDC

(1) Total F&D Costs (\$000s)

Oil and Gas Capital Expenditures	\$ 355,064
Property Acquisitions (net of dispositions)	571,769
Corporate Acquisitions	596,243
Total Oil and Gas FD&A costs	\$ 1,523,076

(2) Change in Future Development Costs (\$000s)

	Total Proved	Proved plus Probable
FDC as of 2008-12-31	\$ 165,400	\$ 221,800
FDC as of 2005-12-31	24,700	34,529
Change in FDC for FD&A Calculation	\$ 140,700	\$ 187,271
FDC of Acquired Properties	144,821	190,110
Change in FDC for F&D Calculation	\$ (4,121)	\$ (2,839)

The following table presents finding and development costs and finding, development and acquisition costs for proved and proved plus probable reserves for the year ending December 31, 2008 and for the prior two years. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. The three-year average is calculated based on the total capital and total reserves over the three-year time period.

COGP Finding, Development and Acquisition Costs^{(a) (b)}
Including Future Development Costs

F&D Costs per boe				
	3-year			
<u>Total Proved</u>	Average^(c)	2008	2007	2006
Including revisions	32.53	49.36	20.39	25.06
Excluding revisions	30.44	35.70	25.55	24.76
<u>Proved plus Probable</u>				
Including revisions	29.97	36.25	24.42	23.99
Excluding revisions	23.39	28.75	20.23	16.80

FD&A Costs per boe				
	3-year			
<u>Total Proved</u>	Average^(c)	2008	2007	2006
Including revisions	36.54	48.36	39.76	30.11
Excluding revisions	35.96	36.45	41.48	30.07
<u>Proved plus Probable</u>				
Including revisions	24.34	35.28	23.31	23.04
Excluding revisions	23.25	28.93	22.85	22.12

Notes:

- (a) F&D costs are based on Company share reserves.
- (b) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (c) Three year average is the average of 2006, 2007 and 2008 calculated based on the total capital and total reserves over the three-year time period.

National Instrument 51-101

Estimation and reporting of oil and natural gas reserves in Canada were governed by National Policy 2B (NP 2B) from the late 1970's until 2003. Effective September 2003 the Canadian Securities Administrators implemented new standards that govern all aspects of reserves disclosure in the form of National Instrument 51-101 (NI 51-101). NI 51-101 requirements were updated effective December 28, 2007. NI 51-101 establishes prescribed disclosures regarding oil and natural gas information. NI 51-101 also enhanced corporate governance by mandating the involvement of independent reserves evaluators in the preparation of reserves data and assigning responsibility for the content of reserves data directly to management and the board of directors. Provident's reserves have been evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook Volumes 1 and 2 ("COGEH") and comply with NI 51-101. Under NI 51-101, proved reserves are defined as having a high degree of certainty to be recoverable. Probable reserves are defined as those reserves that are less certain to be recovered than proved reserves. The targeted levels of certainty, in aggregate, are at least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves and at least 50 percent probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves. Under NI 51-101 standards proved plus probable are considered a "best estimate" of future recoverable reserves. The following outlines some of the key reserves definitions according to NI 51-101.

Reserve Definitions

Acquisitions and Dispositions: Positive or negative changes to the reserves as a result of purchasing or selling all or a portion of an interest in oil and gas properties.

Closing Balance: Reserves assigned at the end of the period.

Company Share: Includes working interest volumes before the deduction of royalties plus volumes equivalent to royalty interests received from others.

Drilling Extensions: Additions to reserves resulting from capital expenditures for step-out drilling in previously discovered reservoirs.

Economic Factors: Changes to reserves between the current and previous reporting periods resulting from different price forecasts, inflation rates, operating and capital cost escalation and regulatory changes.

Exploration Discoveries: Additions to reserves where no reserves were previously booked.

Improved Recovery: Additions to reserves resulting from capital expenditures associated with the installation of enhanced recovery schemes that were not previously included in the reserves category.

Infill Drilling: Additions to reserves resulting from capital expenditures for wells that were drilled in previously discovered reservoirs but were not drilled for enhanced recovery schemes. These additions were not previously included in the initial reserves assignment.

Net Reserves: Includes the company's share of gross reserves after the deduction of royalties plus volumes equivalent to royalty interests received from others and excludes volumes equivalent to royalties paid to others.

Opening Balance: Reserves assigned at the end of the last reporting period.

Production: Reductions in reserves due to production during the reporting period.

Technical Revisions: Positive or negative revisions to a reserves entity resulting from new technical data or revised interpretations on previously assigned reserves.

Working Interest: The Company's interest before royalties paid to or received from others.

Management's Discussion & Analysis

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The following analysis provides a detailed explanation of Provident's operating results for the year ended December 31, 2008 compared to the year ended December 31, 2007 and should be read in conjunction with the consolidated financial statements of Provident. This analysis has been prepared using information available up to March 11, 2009.

Provident Energy Trust has diversified investments in certain segments of the energy value chain. Provident currently operates in two key business segments: Canadian crude oil and natural gas production ("COGP" or "Provident Upstream"), and Provident Midstream. Provident's Upstream business produces crude oil and natural gas from seven core areas in the western Canadian sedimentary basin. The Midstream business unit operates in Canada and the U.S.A. and extracts, processes, markets, transports and offers storage of natural gas liquids within the integrated facilities at Younger in British Columbia, Redwater and Empress in Alberta, Kerrobert in Saskatchewan, Sarnia in Ontario, Superior in Wisconsin and Lynchburg in Virginia. Effective in the first quarter of 2008, Provident's United States oil and natural gas production ("USOGP") business was accounted for as discontinued operations and comparative figures have been reclassified to conform with this presentation (see note 15 to the consolidated financial statements). The USOGP business was sold in two transactions, the first in June and the second in August, 2008.

The Trust has applied the proceeds, net of tax, on the sale of the USOGP business to reduce long-term debt, resulting in a ratio of net debt to total book value capitalization as at December 31, 2008 of 31 percent compared to 40 percent at December 31, 2007 (see "Liquidity and capital resources").

This analysis commences with a summary of the consolidated financial and operating results followed by segmented reporting on the Provident Upstream business unit and the Provident Midstream business unit. The reporting focuses on the financial and operating measurements management uses in making business decisions and evaluating performance.

This analysis contains forward-looking information and statements. See "Forward-looking statements" at the end of the analysis for further discussion.

Consolidated funds flow from operations and cash distributions

Consolidated (\$ 000s, except per unit data)	Year ended December 31,		
	2008	2007	% Change
Funds Flow from Operations and Distributions			
Funds flow from continuing operations	\$ 517,622	\$ 382,684	35
Funds flow from discontinued operations (USOGP) ⁽¹⁾	137,535	85,571	61
Total funds flow from operations	\$ 655,157	\$ 468,255	40
Per weighted average unit - basic and diluted ⁽²⁾	\$ 2.57	\$ 2.04	26
Declared distributions	\$ 352,291	\$ 333,352	6
Per Unit	\$ 1.38	\$ 1.44	(4)
Percent of funds flow from operations distributed ⁽³⁾	58%	77%	(25)

⁽¹⁾ Prior to the sale of USOGP, Provident owned approximately 22 per cent of the BreitBurn Energy Partners, L.P. (MLP) and 96 per cent of BreitBurn Energy Company L.P. In accordance with generally accepted accounting principles (GAAP) in Canada and the United States, these investments were consolidated into Provident's results. On a proportionate basis, Provident's share of funds flow from operations related to discontinued operations (USOGP) for the year ended December 31, 2008 was \$57.9 million.

⁽²⁾ Includes dilutive impact of unit options and convertible debentures.

⁽³⁾ Calculated as declared distributions to unitholders divided by funds flow from operations less distributions to non-controlling interests of \$51.4 million (2007 - \$35.8 million).

Management uses funds flow from operations to analyze operating performance. Funds flow from operations represents cash flow from operations before changes in working capital and site restoration expenditures. Provident also reviews funds flow from operations in setting monthly distributions and takes into account cash required for debt repayment and/or capital programs in establishing the amount to be distributed to Unitholders.

Funds flow from operations as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and therefore it may not be comparable with the calculations of similar measures for other entities. Funds flow from operations as presented is not intended to represent cash flow from operations or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds flow from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital and site restoration expenditures.

For the year ended December 31, 2008, funds flow from operations increased \$186.9 million or 40 percent to \$655.2 million from \$468.3 million for 2007. On a per unit basis, funds flow from operations increased 26 percent in 2008 to \$2.57 per unit from \$2.04 per unit in 2007. Provident Upstream generated \$338.7 million, Provident Midstream \$179.0 million and discontinued operations (USOGP) contributed \$137.5 million of funds flow from operations during 2008. During 2007, Provident Upstream generated funds flow from operations of \$204.3 million, Provident Midstream \$178.4 million, and discontinued operations (USOGP) \$85.6 million.

Canadian oil and gas operations contributed funds flow from operations of \$338.7 million in 2008, an increase of \$134.4 million or 66 percent when compared with \$204.3 million from 2007. This increase was the result of higher realized crude oil, natural gas liquids and natural gas prices in the first nine months of 2008, combined with an increase in production.

The Midstream business unit added \$179.0 million to 2008 funds flow from operations, compared with \$178.4 million recorded in the year ended December 31, 2007. Midstream funds flow from operations reflects a decrease in EBITDA of \$12.9 million or six percent, offset by reduced cash interest charges due to lower debt levels and a reduction in current taxes compared to 2007.

For the year ended December 31, 2008, funds flow from discontinued operations (USOGP) was \$137.5 million, compared to the \$85.6 million in 2007. The increase is primarily driven by increased production due to oil and gas property acquisitions by the MLP in 2007, combined with higher commodity prices. Prior to the sale of USOGP, Provident owned approximately 22 percent of the MLP and 96 percent of BreitBurn. In accordance with generally accepted accounting principles (GAAP) in Canada and the United States, these investments were consolidated into Provident's results. On a proportionate basis, Provident's share of funds flow from operations relating to discontinued operations (USOGP) for the year ended December 31, 2008 was \$57.9 million. Management uses proportionate information to analyze operating performance. The proportionate information as presented here does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities. This proportionate information is not intended to be viewed as an alternative to the corresponding measures of financial performance calculated in accordance with Canadian GAAP.

Declared distributions in 2008 totaled \$352.3 million, 58 percent of funds flow from operations, after distributions to non-controlling interests of \$51.4 million. This compares to \$333.4 million of declared distributions in 2007, 77 percent of funds flow from operations, after distributions to non-controlling interests of \$35.8 million. In previous years, Provident has paid out between 67 percent and 102 percent of its annual funds flow from operations as distributions to unitholders. On a segmented basis, the Midstream business, due to its low sustaining capital requirements, effectively contributed 95 percent of its funds flow from operations for distribution in the year ended December 31, 2008. The remaining distributions were effectively contributed by the oil and natural gas production businesses (Provident Upstream and USOGP) representing 43 percent of their combined funds flow from operations in 2008.

Outlook

Continued price weakness and volatility in commodity markets is having a negative impact on the energy industry on a global scale. This market turmoil has resulted in reduced capital investment, activity levels and ongoing uncertainty in debt and equity markets in the first quarter of 2009. In the current environment, energy firms such as Provident will be challenged to generate cash flow comparable to levels achieved in recent years. Provident actively monitors commodity prices and market conditions on an ongoing basis and will continue to balance reinvestment of cash flow among capital expenditures, distributions and long term debt.

Provident Upstream has a 2009 capital budget of \$88 million and plans to drill a total of 23.8 net wells. Approximately \$36 million is being directed towards development of the Pekisko medium oil play in Northwest Alberta. Three new Pekisko wells have been drilled and surface facilities are now being installed that will enable year round production from four of the five Pekisko wells beginning in the second quarter of 2009. Approximately \$19 million is allocated to the implementation of the first phase of the waterflood project in Dixonville. The remaining \$33 million is budgeted for development initiatives in other areas. 2009 production is expected to average between 23,500 and 25,000 barrels of oil equivalent per day (boed). Subject to pricing assumptions, royalty rates are expected to fall this year to approximately 17 percent including the impact of the new Alberta royalty framework. Operating costs are expected to remain relatively stable in the first half of 2009, but should begin to moderate in the latter half of the year as labour, service and material costs deflate as development activity slows.

Provident Midstream has a 2009 capital budget of approximately \$27 million. This budget will be used, in part, to complete two 500,000 barrel condensate caverns which will enter service at the Redwater facility in the summer of 2009. Work also continues on a third cavern of equal size that is expected to be complete in 2011. Upon completion of these caverns, Provident will own 6.6 million barrels of underground product storage at Redwater. A portion of the 2009 capital budget will be directed towards certain facility optimization and debottlenecking initiatives while approximately \$6 million will be used for normal course facility maintenance. Provident is also allocating a portion of its 2009 capital budget towards the initial phases of a project to construct a depropanizer facility located in Michigan. The Michigan depropanizer is one of several options under consideration to mitigate the financial impact of the potential 6,000 barrels per day curtailment of NGL fractionation capacity at Sarnia which would take effect April 1, 2009, contingent on ongoing contractual negotiations with the facility owner.

NGL margins have strengthened in the first quarter of 2009 compared to the fourth quarter of 2008. This improvement is the result of substantially higher sale prices for propane and butane due to strong winter demand coupled with a lower cost of sales as the majority of the high cost inventory accumulated during 2008 has been depleted.

Distributions

The following table summarizes distributions paid as declared by the Trust since inception:

Record Date	Payment Date	Distribution Amount	
		(Cdn\$)	(US\$)*
2008			
January 24, 2008	February 15, 2008	\$ 0.12	0.12
February 25, 2008	March 14, 2008	0.12	0.12
March 24, 2008	April 15, 2008	0.12	0.12
April 22, 2008	May 15, 2008	0.12	0.12
May 23, 2008	June 13, 2008	0.12	0.12
June 20, 2008	July 15, 2008	0.12	0.12
July 22, 2008	August 15, 2008	0.12	0.12
August 22, 2008	September 15, 2008	0.12	0.11
September 22, 2008	October 15, 2008	0.12	0.10
October 22, 2008	November 14, 2008	0.12	0.10
November 25, 2008	December 15, 2008	0.09	0.07
December 22, 2008	January 15, 2009	0.09	0.07
2008 Cash Distributions paid as declared		\$ 1.38	1.29
2007 Cash Distributions paid as declared		1.44	1.35
2006 Cash Distributions paid as declared		1.44	1.26
2005 Cash Distributions paid as declared		1.44	1.20
2004 Cash Distributions paid as declared		1.44	1.10
2003 Cash Distributions paid as declared		2.06	1.47
2002 Cash Distributions paid as declared		2.03	1.29
2001 Cash Distributions paid as declared			
– March 2001 – December 2001		2.54	1.64
Inception to December 31, 2008 – Distributions paid as declared		\$ 13.77	10.60

* Exchange rate based on the Bank of Canada noon rate on the payment date.

For Canadian tax purposes, 2008 distributions were determined to be 100 percent taxable with no tax deferred return of capital in the hands of Canadian unitholders. The 2007 comparables were 94.8 percent taxable and 5.2 percent tax deferred return of capital. Distributions received by U.S. resident unitholders in 2008 were considered to be 100 percent qualified dividend with no tax deferred return of capital. The 2007 comparables were considered to be 97.6 percent qualified dividend and 2.4 percent tax deferred return of capital. In both Canada and the U.S., any tax-deferred portion would usually be treated as an adjustment to the cost base of the units. Unitholders or potential unitholders should consult their own legal or tax advisors as to their particular income tax consequences of holding Provident units.

Net income

Consolidated (\$ 000s, except per unit data)	Year ended December 31,		
	2008	2007	% Change
Net income	\$ 157,392	\$ 30,434	417
Per weighted average unit			
– basic ⁽¹⁾ and diluted ⁽²⁾	\$ 0.62	\$ 0.13	377

⁽¹⁾ Based on weighted average number of trust units outstanding.

⁽²⁾ Based on weighted average number of trust units outstanding including the dilutive impact of the unit option plan and convertible debentures.

Consolidated (\$ 000s)	Year ended December 31,		
	2008	2007	% Change
Provident Upstream net (loss) income	\$ (306,050)	\$ 45,065	-
Provident Midstream net income (loss)	317,418	(161,020)	-
Net income (loss) from continuing operations	\$ 11,368	\$ (115,955)	-
Net income from discontinued operations (USOGP)	146,024	146,389	-
Consolidated net income	\$ 157,392	\$ 30,434	417

Net income for the year ended December 31, 2008 increased to \$157.4 million compared to \$30.4 million of net income in 2007. On a consolidated basis, the increase in net income in 2008 was driven by favorable operating results compared to 2007 as well as a \$435.7 million change to unrealized gain (loss) on financial derivative instruments, partially offset by a \$416.9 million non-cash goodwill impairment charge (see “Goodwill”).

The Provident Upstream business segment’s net loss was \$306.0 million, a \$351.0 million decrease compared with year ended December 31, 2007 net income of \$45.0 million. A \$131.7 million increase in EBITDA and a \$51.5 million increase in unrealized gains on financial derivative instruments were more than offset by a non-cash goodwill impairment charge of \$416.9 million and, to a lesser extent, increased depletion, depreciation and accretion (DD&A) and a decrease in future income tax recoveries.

The Provident Midstream segment recorded net income of \$317.4 million as compared to a net loss of \$161.0 million in the year ended December 31, 2007. In 2008, Provident Midstream generated a \$14.5 million, or four percent increase in gross operating margin over 2007, reflecting the positive price environment in the first nine months of the year and a \$23.8 million increase over 2007 in foreign exchange gains on U.S. dollar based transactions. These increases were offset by a \$44.4 million increase in realized losses on financial derivative instruments. However, the income was primarily attributable to the requirement under generally accepted accounting principles (GAAP) to “mark-to-market” all financial derivative instruments at a point in time and report these unrealized gains or losses as part of current period income. In 2008, this resulted in \$191.2 million of additional income before future income taxes compared to a \$192.9 million reduction in income before future income taxes in 2007, representing a \$384.2 million swing in unrealized gains on financial derivative instruments over the two year period. Because Provident’s commodity price risk management program involves the use of financial derivative instruments with terms that extend up to five years into the future in the Midstream segment, net earnings can show substantial variation that is not necessarily related to current operations. In addition, a \$73.7 million decrease in future tax expense contributed to the increase in Provident Midstream net income.

Net income from discontinued operations (USOGP) in 2008 was \$146.0 million as compared to \$146.4 million in 2007. The 2008 net income is primarily driven by gains on sale of the discontinued operations, amounting to \$263.6 million. Net income from discontinued operations in 2007 included a dilution gain of \$260.3 million recognized as MLP units were issued to third parties to finance growth.

Reconciliation of non-GAAP measures

The Trust calculates earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items (EBITDA) within its segment disclosure. EBITDA is a non-GAAP measure. A reconciliation between EBITDA and loss from continuing operations before taxes follows:

(\$ 000s)	Year ended December 31,		
	2008	2007	% Change
EBITDA	\$ 566,254	\$ 447,427	27
Adjusted for:			
Cash interest	(50,793)	(54,181)	(6)
Unrealized gain (loss) on financial derivative instruments	221,468	(214,244)	-
Goodwill impairment	(416,890)	-	-
Depletion, depreciation and accretion and other non-cash expenses	(339,856)	(313,199)	9
Loss from continuing operations before taxes	\$ (19,817)	\$ (134,197)	(85)

The following table reconciles funds flow from operations with cash provided by operating activities and distributions to unitholders:

Reconciliation of funds flow from operations to distributions (\$ 000s. except per unit data)	Year ended December 31,		
	2008	2007	% Change
Cash provided by operating activities	\$ 674,426	\$ 464,455	45
Change in non-cash operating working capital	(25,650)	(262)	9,690
Site restoration expenditures	6,381	4,062	57
Funds flow from operations	655,157	468,255	40
Distributions to non-controlling interests	(51,433)	(35,846)	43
Cash retained for financing and investing activities	(251,433)	(99,057)	154
Distributions to unitholders	352,291	333,352	6
Accumulated cash distributions, beginning of year	1,260,177	926,825	36
Accumulated cash distributions, end of year	\$ 1,612,468	\$ 1,260,177	28
Cash distributions per unit	\$ 1.38	\$ 1.44	(4)

Taxes

(\$ 000s)	Year ended December 31,		
	2008	2007	% Change
Capital tax expense	\$ 3,109	\$ 3,762	(17)
Current and withholding tax (recovery) expense	(4,529)	6,352	-
Future income tax recovery	(29,765)	(28,356)	5
	\$ (31,185)	\$ (18,242)	71

Capital taxes in 2008 totaled \$3.1 million, a decrease from the \$3.8 million expense recorded in 2007. The decrease reflects upward adjustments made in 2007 upon filing of previous years tax returns.

The current and withholding tax recovery of \$4.5 million in 2008 compares to \$6.4 million expense in 2007. The decrease in current taxes was due to lower income subject to tax in the U.S.-based Midstream operations.

For the year ended December 31, 2008, future income tax recovery was \$29.8 million, compared with a recovery of \$28.4 million in 2007. In 2008, additional future tax recoveries were recorded as a result of an internal structural reorganization as well as losses created by interest and royalty deductions at the incorporated subsidiary level, offset by future tax expense relating to unrealized gains on financial derivative instruments. The goodwill impairment charge in 2008 had no impact on future income taxes. The 2007 future income tax recovery includes \$88.4 million of expense relating to the enactment of legislation to tax publicly traded trusts in 2011 offset by future tax recoveries created by interest and royalty deductions at the incorporated subsidiary level.

In 2007, future income tax expense included \$88.4 million relating to the enactment of Bill C-52, Budget Implementation Act 2007 by the Canadian government. This bill contains legislation to tax publicly traded trusts including Provident. The legislation limits the tax deductibility of cash distributions after 2010 such that income taxes may become payable in the future. As a result of this legislation, the Trust is required to record the future tax effect of the temporary differences on its flow through entities that are expected to reverse subsequent to 2010.

The Trust has estimated its future income taxes based on estimates of results of operations and tax pool claims and cash distributions in the future assuming no material change to the Trust's current organizational structure. The Trust's estimate of future income taxes does not incorporate any assumptions related to a change in organizational structure until such structures are given legal effect.

The Trust's estimate of its future income taxes will vary as do the Trust's assumptions pertaining to the factors described above, and such variations may be material.

The legislation will not affect the Trust's cash flows from operations and accordingly the Trust's financial condition until 2011, based on our planned compliance with the legislated growth guidelines.

The Trust has approximately \$1.4 billion in tax pools available to claim against taxable income. Provident plans to manage discretionary tax pool claims to defer payment of current taxes as long as possible. Provident has made estimates of taxability in future years based on a number of assumptions including: future product prices; future production and sales; future operating and product costs; future general and administrative costs; future capital expenditures; and general business conditions. Using these assumptions about future events which may or may not occur, Provident estimates that:

- current taxes on Canadian oil and gas operations would occur after 2016; and
- current taxes for midstream operations would occur in 2011.

Provident's tax pools available to shelter future income as at December 31, 2008 are estimated as follows:

As at December 31, 2008

(\$ 000s)	Provident Upstream	Provident Midstream	Total
Intangibles	\$ 610,000	\$ -	\$ 610,000
Tangibles	265,000	270,000	535,000
Non-capital losses	260,000	10,000	270,000
	\$ 1,135,000	\$ 280,000	\$ 1,415,000

Provident also has capital losses of approximately \$370 million which are available to reduce the tax effect of future capital gains.

Interest expense

Continuing operations (\$ 000s, except as noted)	Year ended December 31,		
	2008	2007	% Change
Interest on bank debt	\$ 35,044	\$ 42,477	(17)
Interest on convertible debentures	19,934	20,200	(1)
Discontinued operations portion	(4,185)	(8,496)	(51)
Total cash interest	\$ 50,793	\$ 54,181	(6)
Weighted average interest rate on all long-term debt	5.3%	5.8%	(9)
Debenture accretion and other non-cash interest expense	5,239	4,727	11
Total interest expense	\$ 56,032	\$ 58,908	(5)

Interest expense decreased in 2008 compared to 2007 due to lower debt levels and lower market interest rates. Cash proceeds on the sale of USOGP in June and August of 2008, amounting to \$457.9 million, net of tax, were used to pay down debt.

Financial instruments**Commodity price risk management program**

For the year ended December 31, 2008 \$130.0 million was recorded as a realized loss on financial derivative instruments due to the Commodity Price Risk Management Program (the Program) with \$11.1 million related to Provident Upstream and \$118.9 million associated with the Provident Midstream segment.

In the Provident Upstream segment, the realized loss in 2008 associated with crude oil and natural gas liquids totaled \$11.1 million (\$2.22 per barrel) and a realized gain of nil related to natural gas. The combined total was a loss of \$11.1 million or \$1.10 per boe. In 2007 the Program recorded a realized loss of \$7.9 million related to crude oil and natural gas liquids (\$1.95 per barrel) and a realized gain of \$9.6 million related to natural gas (\$0.28 per mcf). The combined 2007 total was a gain of \$1.7 million, or \$0.18 per boe.

In 2008 the Midstream segment recorded realized losses on crude oil contracts amounting to \$135.6 million (2007 – gains of \$17.9 million), and realized losses of \$17.0 million (2007 - \$48.7 million) related to natural gas. In addition, realized gains associated with NGL market based contracts totaled \$25.9 million (2007 – losses of \$48.2 million), realized gains on Midstream-related foreign exchange contracts were \$5.4 million (2007 - \$4.6 million) and realized gains on electricity-based contracts were \$2.4 million (2007 – nil).

Realized gains on corporate-related foreign exchange contracts in 2008 related to the Program were \$26.8 million (2007 - \$1.3 million). Realized gains and losses on corporate-related foreign exchange contracts are included in foreign exchange (gain) loss and other on the consolidated statement of operations and are allocated to the reporting segments for segmented reporting purposes. The gain in 2008 relates primarily to contracts put in place to mitigate the foreign exchange risk associated with U.S.-denominated taxes payable in connection with the sale of discontinued operations (USOGP).

On a per trust unit basis the opportunity cost of the Program increased to \$0.51 per trust unit in 2008 from \$0.32 per trust unit in 2007. The increased per unit cost in 2008 was more than offset by the funds flow from operations generated by the business units in the high commodity price environment and is reflected in the 26 percent increase in funds flow operations on a per unit basis. In the fourth quarter of 2008, when commodity prices dropped dramatically, the Program helped to stabilize cash flow by contributing \$24.3 million, or 30 percent of fourth quarter funds flow from operations.

At December 31, 2008 the mark-to-market value of open contracts was in a net loss position of \$54.7 million based upon commodity prices prevailing at that date. Under generally accepted accounting principles, these unrealized “mark-to-market” opportunity costs, which relate to financial derivative positions with effective periods ranging from January 2009 through March 2013, are required to be recognized in the financial statements of Provident, affecting current period net income. Fluctuations in the market value of these instruments have no impact on cash flow until the instruments are settled.

Provident's commodity price risk management program utilizes derivative instruments to provide insurance against lower commodity prices and margins. The program provides support for cash distributions, capital programs and bank financing. The risk management strategy protects a percentage of Provident's oil and natural gas production against a decline in commodity prices while, with some products, allowing the Trust to participate in a rising commodity price environment. It provides price stabilization and protection of a percentage of inventory values and fractionation spread margin associated with the Midstream business unit. As well, the Provident risk management strategy reduces foreign exchange risk due to the exposure arising from the conversion of U.S. dollars into Canadian dollars.

Management believes that financial markets currently provide adequate liquidity through price discovery and active credit-worthy counterparties for Provident to continue to execute the program in 2009. The derivative instruments the Trust uses include puts, calls, costless collars, participating swaps, and fixed price products that settle against indexed referenced pricing.

Provident's credit policy governs the activities undertaken to mitigate non-performance risk by counterparties to financial derivative instruments. Activities undertaken include regular monitoring of counterparty exposure to approved credit limits, financial reviews of all active counterparties, utilizing International Swap Dealers Association (ISDA) agreements and obtaining financial assurances where warranted. In addition, Provident has a diversified base of available counterparties.

Disclosure Controls and Procedures: U.S. Sarbanes-Oxley Act

In 2002, the United States Congress enacted the Sarbanes-Oxley Act (SOX), which stipulates that corporations publicly traded on U.S. financial exchanges must assess the effectiveness of their internal controls over financial reporting. As a foreign filer listed on the New York Stock Exchange, Provident is required to conduct the assessment. See "Management's Report on Internal Control Over Financial Reporting" and "Independent Auditors' Report".

Based on their evaluation as of December 31, 2008, Provident's chief executive officer and chief financial officer concluded that Provident's disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act) are effective to ensure that information required to be disclosed by Provident in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission rules and forms. In addition, as of December 31, 2008, there were no changes in Provident's internal controls over financial reporting that occurred during 2008 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting.

Provident will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

The Trust has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting as part of the reporting, certification and attestation requirements of Section 404 of the U.S. Sarbanes-Oxley Act of 2002. For the year ended December 31, 2008 the company's internal controls were found to be operating free of any material weaknesses.

Goodwill

Goodwill represents the excess of the cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed. As at December 31, 2007 Goodwill was comprised of \$416.9 million related to acquisitions in the Canadian oil and gas business and \$100.4 million resulted from the Midstream NGL Acquisition in 2005.

Goodwill is assessed for impairment at least annually, and if an impairment exists, it would be charged to income in the period in which the impairment occurs. The impairment test includes a comparison of the net book value of the Trust's assets, by reporting units, to the estimated fair value of the reporting unit. In 2008, Provident engaged the services of a third-party evaluator to assist in determining fair value. Valuation methodologies included discounted cash flow, a transaction-based approach and a market-based approach, using trading multiples. Goodwill is not amortized.

The Trust performed its annual goodwill impairment test in the fourth quarter of 2008 and determined that the fair value of the Canadian oil and gas production unit was lower than the respective carrying value, primarily due to increasing economic uncertainty in the global market and the resulting higher cost of capital assumptions in the valuation methodologies. Consequently, a goodwill impairment, amounting to \$416.9 million was recorded. The impairment test indicated that the fair value of the Midstream reporting unit was in excess of the respective carrying value, therefore no write down of midstream-related goodwill was required. At December 31, 2008 the goodwill balance of \$100.4 million is related entirely to the Provident Midstream reporting unit.

Liquidity and capital resources

Continuing operations (\$ 000s)	As at December 31,		
	2008	2007	% Change
Long-term debt - revolving term credit facility	\$ 504,685	\$ 923,996	(45)
Long-term debt - convertible debentures (including current portion)	260,994	275,638	(5)
Working capital surplus ⁽¹⁾	(39,041)	(58,732)	(34)
Net debt	\$ 726,638	\$ 1,140,902	(36)
Unitholders' equity (at book value)	1,636,347	1,708,665	(4)
Total capitalization at book value	\$ 2,362,985	\$ 2,849,567	(17)
Total net debt as a percentage of total book value capitalization	31%	40%	(23)

⁽¹⁾ The working capital surplus excludes balances for the current portion of financial derivative instruments.

Provident operates two business units with similar but not identical monthly cash settlement cycles. Midstream revenues are received at various times throughout the month. Provident's working capital position is affected by seasonal fluctuations that reflect commodity price changes, drilling cycles in its oil and gas operations and inventory balances in its Midstream business unit. Provident relies on funds flow from operations, external lines of credit and access to equity markets to fund capital programs and acquisitions.

As a result of the weakening of the global economy, oil and gas industry participants, including Provident, are experiencing more restricted access to capital and anticipate increased borrowing costs. Although Provident's business and asset base have not changed, the lending capacity of financial institutions has been diminished and risk premiums have increased. Management continues to believe that cash flows from operating activities and availability under existing bank facilities will be adequate to allow Provident to move forward with its 2009 capital program. However, these issues will affect Provident as it reviews financing alternatives for future capital expenditures and potential acquisition opportunities in the current lower commodity price environment.

Substantially all of Provident's accounts receivable are due from customers and joint venture partners in the oil and gas and midstream services and marketing industries and are subject to credit risk. Provident partially mitigates associated credit risk by limiting transactions with certain counterparties to limits imposed by Provident based on management's assessment of the creditworthiness of such counterparties. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

As at December 31, 2008, Provident held non-bank sponsored asset-backed commercial paper with a face value of \$6.1 million. Provident has recorded an impairment write-down amounting to \$4.3 million in 2008 (2007 - \$1.8 million) to reflect the fair value of these assets at December 31, 2008, determined to be nil. The write-down is included in net income as part of foreign exchange (gain) loss and other.

Contractual obligations

Consolidated		Payment due by period				
		Less				More
(\$ millions)	Total	than 1		1 to 3	4 to 5	than 5
		year		years	years	years
Long-term debt - revolving term credit facility ^{(1) (3)}	\$ 548.8	\$ 16.8	\$	532.0	\$ -	\$ -
Long-term debt - convertible debentures ^{(2) (3)}	321.6	42.5		175.8	103.3	-
Operating lease obligations	195.6	22.3		37.6	29.1	106.6
Total	\$ 1,066.0	\$ 81.6	\$	745.4	\$ 132.4	\$ 106.6

⁽¹⁾ The terms of the Canadian credit facility have a revolving three year period expiring on May 30, 2011.

⁽²⁾ Includes current portion of convertible debentures.

⁽³⁾ Includes associated interest and principal payments.

Long-term debt and working capital

As at December 31, 2008 Provident had drawn on 45 percent of its term credit facility of \$1,125 million as compared to 81 percent drawn as at December 31, 2007. The decrease in the level of bank debt reflects the application of \$457.9 million of cash proceeds, net of tax, realized on the disposition of USOGP. During 2008, capital expenditures and distributions to unitholders were roughly equivalent with the sum of funds flow from operations, DRIP proceeds and changes in working capital.

At December 31, 2008 Provident had letters of credit guaranteeing Provident's performance under certain commercial and other contracts that totaled \$35.2 million, increasing bank line utilization to 48 percent. The guarantees at December 31, 2007 totaled \$31.6 million.

Provident's working capital from continuing operations increased by \$106.6 million from a deficit of \$89.4 million to a surplus of \$17.2 million as at December 31, 2008. The significant increase is primarily due to a \$132.0 million decrease in net current financial derivative instrument liabilities, a \$103.2 million decrease in accounts payable and accrued liabilities, partially offset by decreased accounts receivable of \$93.6 million and a \$38.5 million decrease in inventory.

The ratio of net debt (as calculated under "Liquidity and capital resources") to funds flow from continuing operations in 2008 was 1.4 to one, compared to 3.0 to one in 2007. The decrease reflects a decrease in net debt as well as higher funds flow from operations. On a segmented basis, the Provident Upstream business had a ratio of net debt to funds flow from operations in 2008 of 0.7 to one (2007 – 1.8 to one). The ratio for the Provident Midstream business unit was 2.7 to one in 2008, compared to 4.3 to one in 2007.

Trust units

For the year ended December 31, 2008 the Trust issued six thousand units on conversion of convertible debentures (2007 – 0.5 million units). An additional 0.2 million units were issued pursuant to the unit option plan for the year ended December 31, 2008 (2007 – 0.8 million units). Under Provident's Premium Distribution, Distribution Reinvestment (DRIP) and Optional Unit Purchase Plan program 6.3 million units were issued or are to be issued in 2008 representing proceeds of \$53.8 million (2007 – 4.5 million units for proceeds of \$50.5 million).

At December 31, 2008 management and directors held less than one percent of the outstanding trust units.

Capital expenditures and funding

Continuing operations (\$ 000s)	Year ended December 31,		
	2008	2007	% Change
Capital Expenditures			
Capital expenditures and site restoration expenditures	\$ (253,328)	\$ (182,175)	39
Property acquisitions, net	(24,181)	(13,050)	
Corporate acquisitions	-	(469,795)	
Net capital expenditures	\$ (277,509)	\$ (665,020)	(58)
Funded By			
Funds flow from continuing operations net of declared distributions to unitholders	\$ 165,331	\$ 49,332	235
Proceeds on sale of discontinued operations, net of tax	457,906	-	-
(Decrease) increase in long-term debt	(440,244)	169,122	-
Issue of trust units, net of cost; excluding DRIP	1,672	362,418	(100)
DRIP proceeds	53,838	50,491	7
Change in working capital, including cash, sale of assets and change in investments	39,006	33,657	16
Net capital expenditure funding	\$ 277,509	\$ 665,020	(58)

Net capital expenditures were funded by a combination of funds flow from operations, debt, equity issued from treasury through public offerings, the DRIP program and proceeds on the sale of discontinued operations.

Non-cash unit based compensation

Non-cash unit based compensation includes expenses or recoveries associated with Provident's restricted and performance unit plan as well as the unit option plan. Provident accounts for the unit option plan using the fair value of the option at the time of issue. The other unit based compensation is recorded at the estimated fair value of the notional units granted. Compensation expense associated with the plans is recognized in earnings over the vesting period of each plan. The expense or recovery associated with each period is recorded as non-cash unit based compensation (a component of general and administrative expense). A portion relating to operational employees at field and plant locations is also allocated to operating expense. For the year ended December 31, 2008, Provident recorded unit based compensation expense of \$4.4 million (2007 - \$10.2 million) and made related cash payments of \$8.3 million (2007 - \$1.8 million). The expense is lower in 2008 as a result of a lower Provident trust unit trading price, upon which the compensation is based. At December 31, 2008, the current portion of the liability totaled \$9.4 million (December 31, 2007 - \$9.9 million) and the long-term portion totaled \$8.6 million (December 31, 2007 - \$12.4 million).

Provident Upstream segment review

Crude oil and natural gas liquids prices

Provident Upstream (\$ per bbl)	Year ended December 31,		
	2008	2007	% Change
Oil per barrel			
WTI (US\$)	\$ 99.65	\$ 72.31	38
Exchange rate (from US\$ to Cdn\$)	\$ 1.07	\$ 1.07	-
WTI expressed in Cdn\$	\$ 106.33	\$ 77.67	37
Realized pricing before financial derivative instruments			
Crude oil	\$ 82.79	\$ 56.74	46
Natural gas liquids	\$ 76.88	\$ 55.07	40
Crude oil and natural gas liquids	\$ 82.27	\$ 56.54	46

The above realized prices are net of transportation expense.

For the year ended December 31, 2008 Provident's realized crude oil and natural gas liquids price, prior to the impact of financial derivative instruments, increased by 46 percent to average \$82.27 compared to \$56.54 in 2007. The 2008 increase related to a 38 percent higher US\$ WTI crude oil price and narrower pricing differentials on crude oil streams.

Natural gas price

Provident Upstream (\$ per mcf)	Year ended December 31,		
	2008	2007	% Change
AECO monthly index (Cdn\$ per mcf)	\$ 8.12	\$ 6.59	23
Corporate natural gas price per mcf before financial derivative instruments (Cdn\$)	\$ 8.23	\$ 6.42	28

The above prices are net of transportation expense.

For the year ended December 31, 2008 Provident's realized natural gas price, excluding financial derivative instruments, increased 28 percent as compared to 2007, greater than the increase in the benchmark AECO monthly index price. Provident's gas portfolio includes aggregator contracts sold on a term basis that can differ from the benchmark price and sells to the spot market on monthly or daily indices and receives prices which take into account heat content. Provident's realized prices and changes in prices can therefore differ from benchmark indices.

Production

Provident Upstream	Year ended December 31,		
	2008	2007	% Change
Daily production			
Crude oil (bpd)	12,473	9,797	27
Natural gas liquids (bpd)	1,203	1,316	(9)
Natural gas (mcfd)	84,039	92,378	(9)
Oil equivalent (boed) ⁽¹⁾	27,683	26,509	4

⁽¹⁾ Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

For the year ended December 31, 2008, Provident Upstream production averaged 27,683 boed, a four percent increase compared to 26,509 boed in 2007. The increase is primarily a result of the full year effect in 2008 of the two acquisitions, Capitol in June of 2007 and Triwest in December of 2007, the additional working interests acquired throughout 2008, and the production volumes added through drilling and optimization activities, partially offset by production declines typical in the Western Canadian Sedimentary Basin. The Capitol acquisition became Provident Upstream's newest core area, Dixonville, and the Triwest acquisition is included in the Southeast Saskatchewan core area.

Production for 2008 was weighted 51 percent natural gas and 49 percent crude oil and natural gas liquids. This compared to 2007 production weighted 58 percent natural gas and 42 percent crude oil and natural gas liquids. Year-over-year, the change in mix reflects the full year effect for 2008 of the two acquisitions in 2007 which were primarily light/medium crude oil production.

Provident Upstream production summarized by core areas is as follows:

Provident Upstream	Year ended December 31,		
	2008	2007	% Change
Daily Production - by area (boed) ⁽¹⁾			
West Central Alberta	6,271	7,011	(11)
Southern Alberta	4,883	5,622	(13)
Northwest Alberta	4,690	4,905	(4)
Dixonville ⁽²⁾	3,764	2,058	83
Southeast Saskatchewan	3,061	1,769	73
Southwest Saskatchewan	1,333	1,726	(23)
Lloydminster	3,681	3,418	8
	27,683	26,509	4

⁽¹⁾ Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

⁽²⁾ Dixonville production in 2007 represents production from June 19, 2007 (date of Capitol Energy Resources Ltd. acquisition) amounting to 3,852 boed for the 195 days.

Revenue and royalties

Provident Upstream		Year ended December 31,		
(\$ 000s except per boe and mcf data)		2008	2007	% Change
Oil				
Revenue	\$	377,976	\$ 202,909	86
Realized loss on financial derivative instruments		(11,113)	(7,905)	41
Royalties		(69,897)	(39,211)	78
Net revenue	\$	296,966	\$ 155,793	91
Net revenue (per barrel)	\$	65.05	\$ 43.57	49
Royalties as a percentage of revenue		18.5%	19.3%	
Natural gas				
Revenue	\$	253,183	\$ 216,626	17
Realized gain on financial derivative instruments		11	9,633	(100)
Royalties		(44,715)	(41,154)	9
Net revenue	\$	208,479	\$ 185,105	13
Net revenue (per mcf)	\$	6.78	\$ 5.49	23
Royalties as a percentage of revenue		17.7%	19.0%	
Natural gas liquids				
Revenue	\$	33,857	\$ 26,451	28
Royalties		(8,528)	(6,681)	28
Net revenue	\$	25,329	\$ 19,770	28
Net revenue (per barrel)	\$	57.53	\$ 41.16	40
Royalties as a percentage of revenue		25.2%	25.3%	
Total				
Revenue	\$	665,016	\$ 445,986	49
Realized (loss) gain on financial derivative instruments		(11,102)	1,728	-
Royalties		(123,140)	(87,046)	41
Net revenue	\$	530,774	\$ 360,668	47
Net revenue (per boe)	\$	52.39	\$ 37.27	41
Royalties as a percentage of revenue		18.5%	19.5%	

Note: the above revenue, net revenue and net revenue per boe figures are presented net of transportation expenses.

For the year ended December 31, 2008 Provident Upstream production revenue was \$665.0 million, an increase of 49 percent from \$446.0 million in 2007. The increase in revenue was a result of the four percent increase in production and higher realized crude oil, natural gas liquids, and natural gas prices. Royalties as a percentage of revenue had a slight decrease to 18.5 percent reflecting capital expenditures on gas facilities. The preceding factors offset by the \$11.1 million realized loss on financial derivative instruments compared to a \$1.7 million realized gain in 2007, account for net revenue of \$530.8 million in 2008, 47 percent higher than the \$360.7 million recorded in 2007.

Net revenue per boe in 2008 increased 41 percent to \$52.39 from \$37.27 in 2007 resulting primarily from higher realized crude oil, natural gas liquids, and natural gas prices and a higher percentage of production from crude oil and natural gas liquids.

Production expense

Provident Upstream (\$ 000s, except per boe data)	Year ended December 31,		
	2008	2007	% Change
Production expenses	\$ 138,173	\$ 112,387	23
Production expenses (per boe)	\$ 13.64	\$ 11.62	17

For the year ended December 31, 2008 production expenses increased 23 percent to \$138.2 million from \$112.4 million and increased by 17 percent on a per boe basis to \$13.64 per boe from \$11.62 per boe in the prior year. The increase in total costs was due to the four percent increase in production combined with returning higher operating cost wells to production in the second and third quarters of 2008 to take advantage of record crude oil prices and associated netbacks. The increased commodity prices resulted in high prices for fuel and power and high industry activity levels in the second and third quarters of 2008 resulted in increased costs for service related activities for down-hole and maintenance work. The wells returned to production included higher operating costs for fluid hauling, and associated maintenance and down-hole costs. In addition, colder weather in the first and fourth quarters of 2008 impacted operations and unscheduled turnarounds in Northwest Alberta were performed in the fourth quarter of 2008 to take advantage of circumstances resulting from a third-party pipeline outage.

Operating netback

Provident Upstream (\$ per boe)	Year ended December 31,		
	2008	2007	% Change
Netback per boe			
Gross production revenue	\$ 65.64	\$ 46.09	42
Royalties	(12.15)	(9.00)	35
Operating costs	(13.64)	(11.62)	17
Field operating netback	39.85	25.47	56
Realized (loss) gain on financial derivative instruments	(1.10)	0.18	-
Operating netback after realized financial derivative instruments	\$ 38.75	\$ 25.65	51

Provident Upstream operating netbacks have transportation expense netted against gross production revenue.

The 2008 field operating netback of \$39.85 per boe was 56 percent above the \$25.47 per boe for the prior year. This reflects increased realized crude oil, natural gas liquids, and natural gas prices and an increase in Provident's production mix of crude oil and natural gas liquids to 49 percent in 2008 from 42 percent in 2007. This was partially offset by 17 percent higher operating costs per boe. Royalties, which are price sensitive, increased by 35 percent on a boe basis reflecting the higher commodity prices. The 2008 operating netbacks after financial derivative instruments increased by 51 percent to \$38.75 from \$25.65 in the prior year due to the preceding factors as well as the realized loss on financial derivative instruments of \$1.10 per boe compared to \$0.18 per boe realized gain in the prior year.

General and administrative

Provident Upstream (\$ 000s, except per boe data)	Year ended December 31,		
	2008	2007	% Change
Cash general and administrative	\$ 36,191	\$ 27,102	34
Non-cash unit based compensation	(2,199)	3,698	-
	\$ 33,992	\$ 30,800	10
Cash general and administrative (per boe)	\$ 3.57	\$ 2.80	28

For the year ended December 31, 2008, cash general and administrative expenses were \$36.2 million (2007 - \$27.1 million), an increase of 34 percent. On a boe basis, cash general and administrative expenses in 2008 increased 28 percent to \$3.57 per boe from \$2.80 per boe in 2007. The 2008 cash general and administrative expenses included \$4.5 million, or \$0.45 per boe (2007 - \$0.9 million or \$0.09 per boe) related to payments associated with unit based compensation. The unit based expense was accrued over a three-year vesting period as non-cash unit based compensation, consequently, there is an offsetting reduction in non-cash unit based compensation when the payments are made. Excluding these payments, cash general and administrative expenses were \$31.7 million, or \$3.12 per boe (2007 - \$26.2 million or \$2.71 per boe). The increase reflects higher office-related expenses, particularly rent, and costs associated with the previously announced strategic evaluation of Provident's business units, including an internal structural reorganization completed in the fourth quarter of 2008.

Non-cash unit based compensation was a recovery of \$2.2 million in 2008 and an expense of \$3.7 million in 2007. Excluding the related cash payments in each year, non-cash unit based compensation was an expense of \$2.3 million in 2008 (2007 - \$4.6 million). Non-cash unit based compensation is lower in 2008 as a result of a lower Provident trust unit trading price, upon which the compensation is based.

Capital expenditures

Provident Upstream (\$ 000s)	Year ended December 31,	
	2008	2007
Capital expenditures - by category		
Geological, geophysical and land	\$ 25,474	\$ 4,519
Drilling and recompletions	146,992	113,425
Facilities and equipment	34,514	13,378
Office and other	2,167	14,887
Total additions	\$ 209,147	\$ 146,209
Capital expenditures - by area		
West central Alberta	\$ 10,326	\$ 9,051
Southern Alberta	19,852	13,079
Northwest Alberta	79,445	35,993
Dixonville	60,339	43,801
Southeast Saskatchewan	21,175	5,069
Southwest Saskatchewan	5,369	15,196
Lloydminster	8,181	9,235
Other	4,460	14,785
Total additions	\$ 209,147	\$ 146,209
Property acquisitions, net	\$ 24,181	\$ 13,050

In 2008, Provident's Upstream business unit spent \$207.0 million on capital expenditures before office and other capital costs. Internal development activities included 87.4 net wells drilled for the year ended December 31, 2008 with a 99 percent success rate. Provident's drilling activities in 2008 were more focused on crude oil compared to 2007. Provident spent \$79.4 million in Northwest Alberta, primarily on drilling and completion activities which included 14.0 net wells drilled, the infrastructure and tie-in activities associated with the 2007/2008 winter drilling program and preparation work to start the 2008/2009 winter drilling program. Facility and pipeline work in Northwest Alberta included preparation work to develop the emerging Pekisko opportunity and 95.4 net sections (approximately 61,000 acres) of land were also acquired for the Pekisko opportunity. Provident spent \$60.3 million in the newest core area, Dixonville, primarily on drilling and completion activities which resulted in 41.0 net wells drilled. In the Southeast Saskatchewan core area, \$21.2 million was spent which included 13.8 net wells drilled. As oil prices increased during the first half of 2008, capital work was primarily focused on oil drilling in Dixonville and primarily light oil drilling in Southeast Saskatchewan. The shallow gas drilling program in Southwest Saskatchewan was reduced. In Southern Alberta, \$19.9 million was primarily spent on drilling activity and recompletions, which included 14.1 net wells drilled, and on facility upgrades and infrastructure work. The \$26.2

million of capital spent in the remaining core areas included drilling, completion, tie-ins, recompletions, facility upgrades and production optimization activities.

Additions to proved plus probable reserves (before revisions) through internal capital replaced approximately 70 percent of annual production.

In 2008, Provident also spent \$24.2 million on property acquisitions primarily on acquiring additional working interests in Northwest Alberta and Southeast Saskatchewan.

Depletion, depreciation and accretion (DD&A)

Provident Upstream (\$ 000s, except per boe data)	Year ended December 31,		
	2008	2007	% Change
DD&A	\$ 304,909	\$ 256,723	19
DD&A (per boe)	\$ 30.09	\$ 26.53	13

The Provident Upstream DD&A rate of \$30.09 per boe increased 13 percent for 2008 compared to \$26.53 per boe in 2007. The increase was partly as a result of the two acquisitions of Capitol and Triwest in 2007. In addition, 2008 expenditures on geological, geophysical, land and facilities added to costs to be depleted without directly adding proved reserves. The recent Upstream acquisitions and the Rainbow assets acquired in 2006 differed from earlier acquisitions in that they included significant reserves that were not yet proved. Since depletion calculations are based on proved reserves, acquisitions with unproved reserves generally result in higher depletion rates. The impact of this, combined with the higher cost of acquiring or drilling proved reserves in western Canada in an environment with higher commodity prices and increased drilling costs, will be reflected in the DD&A rate going forward.

In 2008, DD&A also includes accretion expense associated with asset retirement obligation of \$3.4 million (2007 - \$2.5 million).

As part of the reconciliation of Provident's financial statements to United States generally accepted accounting principles (U.S. GAAP), disclosed in note 18 to the consolidated financial statements, the Trust has reflected additional depletion in 2008 of \$814.0 million (2007 - \$181.6 million) and a related future income tax recovery of \$214.3 million (2007 - \$52.2 million) as a result of the application of the U.S. GAAP ceiling test. These charges were not required under Canadian generally accepted accounting principles.

Provident Midstream business segment review

The Midstream business

The Midstream business unit extracts, processes, stores, transports and markets natural gas liquids (NGL) for Provident and offers these services to third party customers. The Provident Midstream segment contains three business lines:

Empress East
Redwater West
Commercial Services

The Empress East business line is comprised of the following core assets:

- Approximately 2.0 Bcfd of extraction capacity at Empress, Alberta. This is the combination of 67.5 percent ownership of the 1.2 Bcfd capacity Provident Empress NGL extraction plant, 12.4 percent ownership in the 1.1 Bcfd capacity ATCO Plant, 8.3 percent ownership in the 2.4 Bcfd capacity Spectra Plant and 33.0 percent ownership in the 2.7 Bcfd capacity BP Empress 1 Plant.
- 100 percent ownership of a 50,000 bpd debutanizer at Empress, Alberta.
- 50 percent ownership in the 130,000 bpd Kerrobert pipeline and 2.5 mmbbl underground storage facility near Kerrobert, Saskatchewan which facilitates injection into the Enbridge pipeline system. Along the Enbridge pipeline system in Superior, Wisconsin, Provident holds an 18.3 percent ownership of a 300,000 barrel storage staging facility and 18.3 percent ownership of the 6,600 bpd depropanizer.
- In Sarnia, Ontario, 10.3 percent ownership of an approximately 150,000 bpd fractionator, 1.7 mmbbl of raw product storage capacity and 18 percent of 5.0 mmbbl of finished product storage and rail, truck and pipeline terminalling. An additional 0.5 mmbbls of specification product storage is also available in the Sarnia area.
- A propane distribution terminal at Lynchburg, Virginia.
- A rail car fleet of approximately 300 rail cars under long-term lease agreement.

The Redwater West business line is comprised of the following core assets:

- 100 percent ownership of the Redwater NGL fractionation facility, incorporating a 65,000 bpd fractionation, storage and transportation facility that includes 12 pipeline receipt and delivery points, railcar loading facilities with direct access to CN rail and indirect access to CP rail, two propane truck loading facilities, six million gross barrels of salt cavern storage, and a 60,000 bpd condensate rail offloading facility with a 300 railcar storage yard. The facility can process high-sulphur NGL streams and is one of only two ethane-plus fractionation facilities in western Canada capable of extracting ethane from the natural gas liquids stream.
- In 2009, two new caverns (approximately 500,000 barrels each) will be brought into service and are planned to be used for condensate storage.
- Approximately 7,000 bpd of leased fractionation capacity at other facilities.
- 43.3 percent direct ownership and 100 percent control of all products from the 38,500 bpd Younger NGL extraction plant located at Taylor in northeastern British Columbia. The Younger plant supplies local markets as well as Provident's Redwater fractionation facility near Edmonton.
- 100 percent ownership of the 565 kilometer proprietary Liquids Gathering System ("LGS") that runs along the Alberta-British Columbia border providing access to a highly active basin for liquids-rich natural gas exploration and exploitation. Provident also has long-term shipping rights on the Pembina pipeline system that extends the product delivery transportation network through to the Redwater fractionation facility.
- A rail car fleet of approximately 700 rail cars under long-term lease agreement.

The Commercial Services business line:

The Commercial Services business line includes services such as fractionation, storage, and loading at Provident's Redwater facility on a fee basis. It also includes pipeline tariff income from Provident's ownership of the Liquids Gathering System in Northwest Alberta which flows into Pembina's pipeline from LaGlace to Redwater. Provident also collects tariff income from its 50 percent ownership in the Kerrobert Pipeline which transports NGLs from Empress to Kerrobert for injection into the Enbridge pipeline for delivery to Sarnia. Provident owns a debutanizer at its Empress facility, which removes condensate from the NGL mix for sale as a diluent to blend with heavy oil. This service is provided to a major energy company on a long term cost of service basis. Earnings from this business line of the Midstream segment have little direct exposure to market prices volatility and are thus relatively stable.

Long term contracts

At the Redwater fractionation facility, a significant portion of the available propane plus fractionation capacity is contracted through a long term fee for service arrangement with third parties.

In 2006 and early 2007, Provident commissioned a 60,000 bpd condensate rail off-loading terminal at Redwater, a significant portion of which is under long term contracts with two major energy producers.

The ethane produced from Provident's facilities at Empress and Redwater is largely sold under long term contracts.

Provident has a long term contract on a cost of service basis for the majority of its 50,000 bbl/d Empress debutanizer facility. Provident also has a long term contract for 500,000 barrels of specification product storage in the Sarnia area.

The 2008 Provident Midstream business unit results can be summarized as follows:

(\$ 000s)	Year ended December 31,		
	2008	2007	% Change
Empress East Margin	\$ 157,976	\$ 183,565	(14)
Redwater West Margin	142,836	94,600	51
Commercial Services Margin	46,541	54,649	(15)
Gross operating margin	347,353	332,814	4
Realized loss on financial derivative instruments	(118,917)	(74,474)	60
Cash general and administrative expenses	(35,528)	(28,669)	24
Foreign exchange gain (loss) and other	19,853	(3,996)	-
Provident Midstream EBITDA	\$ 212,761	\$ 225,675	(6)

Gross operating margin

The Empress East business line extracts NGLs from natural gas at the Empress straddle plants and sells finished products into markets in Central Canada and the Eastern United States. The margin in this business is determined primarily by the "frac spread ratio", which is the ratio between crude oil prices and natural gas prices. The higher the ratio, the better this business line will perform. There is also a differential between propane, butane and condensate (collectively, these products are referred to as "propane-plus") prices and crude oil prices which can change prices received and margins realized for Midstream products separate from frac spread ratio changes. Operating margins reflect the prices realized on sale of these products less the weighted average cost of purchasing, fractionating, storing and transporting the products. The business is seasonal and carries inventory that generally builds over the second and third quarters of the year and is sold in the fourth quarter and the first quarter of the following year.

The 2008 gross operating margin from Empress East was \$158.0 million compared to \$183.6 million in 2007. The decrease reflects approximately 18 percent higher propane-plus prices offset by 29 percent higher propane-plus costs as a result of a significant increase in gas prices in 2008. Frac spread ratios during the first nine months of 2008 averaged 14.3, compared to 11.6 during the same period in 2007. However, frac spread ratios reversed in the fourth quarter of 2008 averaging 11.2, compared to 15.7 during the fourth quarter of 2007. In addition, 2008 experienced a

significant decline in the sales price of propane relative to the price of crude oil. Posted prices at Mont Belvieu for propane in 2008 averaged 60 percent of WTI, compared to 70 percent in 2007. Overall strong performance in the first three quarters of 2008 was offset in the fourth quarter by higher cost inventory built up in the second and third quarters at historically high product prices, then subsequently sold in the fourth quarter, when product prices had dropped significantly.

Subsequent to year end, conditions have shown some improvement. The frac spread ratio in January 2009 has improved by nine percent compared to December, and the price of propane as a percentage of WTI has increased to 72 percent.

The Redwater West business line purchases an NGL mix from various producers and fractionates it into finished products at the Redwater fractionation facility near Edmonton, Alberta. Because the feedstock for this business line is primarily NGL mix rather than natural gas, the frac spread ratio has a smaller impact on margin than in the Empress East business line. This facility also has the largest rail rack in Western Canada to receive products for delivery into the local condensate market. Provident has considerably increased its participation in the condensate market over the past year, reflecting the increased demand for condensate as diluent for heavy oil production.

In 2008, the operating margin for the Redwater West business line was \$142.8 million (2007 - \$94.6 million). The 51 percent increase in margin was driven by a 15 percent increase in propane-plus sales volumes, primarily condensate, and a 26 percent increase in propane-plus prices versus a 25 percent increase in costs.

The Commercial Services business line generates income from stable fee-for-service contracts to provide fractionation, storage, loading, and marketing services to upstream producers. Income from pipeline tariffs from Provident's ownership in NGL pipelines is also included in this business line. In 2008, the margin for this business line was \$46.5 million (2007 - \$54.6 million). In 2008, while the margin for this business line was 15 percent lower, it does include a 46 percent increase in fees associated with our offloading terminal, due to increased condensate business. In 2007, the Commercial Services margin included payments received for product quality adjustments at our condensate offloading facility. These payments increased operating margin in 2007, are generally non-recurring and account for the year over year decrease in operating margin.

Operations – Provident Midstream NGL sales volumes

Provident Midstream sold 119,649 bpd in 2008, compared with 120,785 in 2007. Higher propane-plus volumes were offset by lower ethane volumes reflecting reduced demand in the fourth quarter of 2008.

Earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items (“EBITDA”) and funds flow from operations

For 2008, Provident Midstream EBITDA decreased \$12.9 million or six percent from \$225.7 million in 2007. A \$14.5 million increase in gross operating margin as described above, as well as foreign exchange gains on U.S. dollar-based transactions, were tempered by a \$44.4 million increase in realized losses on financial derivative instruments and higher cash general and administrative and other costs. Funds flow from operations for 2008 was \$179.0 million, an increase of \$0.6 million above the \$178.4 million in 2007. The increase in funds flow from operations reflects the lower EBITDA being more than offset by reduced interest charges and a current tax recovery.

Cash general and administrative expenses and other were \$35.5 million for 2008 (2007- \$28.7 million). Included in this amount is \$3.8 million (2007 - \$0.9 million) related to payments associated with unit based compensation. The expense was accrued over a three-year vesting period as non-cash unit based compensation, consequently there is an offsetting reduction in non-cash unit based compensation when the payments are made. Excluding these payments, cash general and administrative expenses were \$31.7 million in 2008 (2007 - \$27.8 million). The increase reflects higher office-related expenses, particularly rent, and costs associated with the previously announced strategic evaluation of Provident's business units, including an internal structural reorganization completed in the fourth quarter of 2008.

Management uses EBITDA to analyze the operating performance of the Midstream business unit. EBITDA as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. EBITDA as presented is not intended to represent operating cash flow from operations or operating profits for the period nor should it be viewed as an alternative to cash flow from operations from operating activities, net earnings or other measures of financial

performance calculated in accordance with Canadian GAAP. All references to EBITDA throughout this report are based on earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items ("EBITDA").

Capital expenditures

Provident Midstream capital expenditures in 2008 totaled \$37.8 million. In 2008, \$20.8 million was spent on continued development of cavern storage, the condensate offloading and terminalling facility, and expansion to the recently completed truck loading facilities. In addition, \$7.7 million was added to capitalized line-fill, \$8.2 million was spent on sustaining capital requirements and \$1.1 million was spent primarily on development of systems to improve information flow within the business unit.

Discontinued operations (USOGP)

In February 2008, the Trust announced a strategic process respecting the decision to sell the operations that comprise the United States oil and natural gas production (USOGP) business. This business was comprised of approximately 22 percent ownership of BreitBurn Energy Partners, L.P., a publicly-traded U.S. Master Limited Partnership ("the MLP"). This MLP ownership also included units held by the General Partner of which Provident owned approximately 96 percent. In addition, Provident owned approximately 96 percent of privately held BreitBurn Energy Company L.P. ("BreitBurn") which operates assets in California.

Effective in the first quarter of 2008, the USOGP business was accounted for as discontinued operations. Discontinued operations (USOGP) includes the consolidated results of 100 percent of the MLP and BreitBurn. Non-controlling interests are comprised mainly of the public ownership in the MLP, and to a lesser extent the ownership interests of the managers in the MLP and BreitBurn, as well as third party investment in USOGP's land development project, which commenced in 2006.

In June 2008, the Trust sold a portion of the USOGP business, consisting of its 22 percent interest in BreitBurn Energy Partners, L.P. (MLP) and its 96 percent interest in BreitBurn GP LLC, for cash proceeds, net of transaction costs, of U.S. \$342.2 million. The Trust has recorded a gain on sale of \$187.9 million and \$127.7 million in current tax expense related to this transaction. Also recorded was a realized foreign exchange loss of \$30.3 million, representing the recognition of the related portion of the foreign exchange loss in accumulated other comprehensive income, which was generated since inception in 2006. These amounts are recorded as part of net income from discontinued operations for the year ended December 31, 2008.

In August 2008, the Trust sold the remaining portion of the USOGP business, comprised of an approximate 96 percent interest in BreitBurn Energy Company L.P., for total consideration of U.S. \$300.4 million, consisting of cash proceeds, net of transaction costs, of U.S. \$290.4 million and a U.S. \$10 million note. The Trust has recorded a gain on sale of \$75.7 million and \$66.9 million in current tax expense related to this transaction. Also recorded was a realized foreign exchange loss of \$26.8 million, representing the recognition of the related portion of the foreign exchange loss in accumulated other comprehensive income, which was generated since acquisition in 2004. These amounts are recorded as part of net income from discontinued operations for the year ended December 31, 2008.

Quicksilver Resources Inc. ("Quicksilver") filed a lawsuit on October 31, 2008 against the MLP, certain of its directors (including three Provident nominees), and Provident. The claim relates to a transaction between the MLP and Quicksilver and certain other MLP matters. Quicksilver alleges, among other things, that it was induced to enter into a contribution agreement pursuant to which it contributed assets to the MLP by false representations as to Provident's relationship with the MLP. The transaction involved the issuance by the MLP to Quicksilver of approximately U.S.\$700 million of units of the MLP. The litigation is in its very early stages, and it is not possible at this time to assess the potential exposure of Provident in the event of an adverse verdict. Provident believes the claims made against it in the lawsuit are without merit and will vigorously defend itself and its named director nominees against these claims.

Foreign ownership

Based on information received from our transfer agent and financial intermediaries in January 2009, an estimated 85 percent of our outstanding trust units are held by non-residents. However, this estimate may not be accurate as it is based on certain assumptions and data from the securities industry that does not have a well-defined methodology to determine the residency of beneficial holders of securities.

The Trust qualifies as a Mutual Fund Trust under the Canadian Income Tax Act because substantially all the value of its asset portfolio is derived from non-taxable Canadian properties, comprised principally of royalties and interest on inter-company debt. Provident monitors on an ongoing basis the value of its asset portfolio to confirm that substantially all of the value of its asset portfolio is derived from non-taxable Canadian properties.

On September 17, 2003, Canadian unitholders approved an amendment to the Trust's Trust Indenture providing that residency restriction provisions need not be enforced while the Trust continues to qualify as a Mutual Fund Trust under Canadian tax legislation. To allow Provident to remain a Mutual Fund Trust and to execute a business plan that maximizes unitholder returns without regard to the types of assets the Trust may hold, the approved amendment provides for Provident's Board of Directors to have sole discretion to determine whether and when it is appropriate to reduce or limit the number of trust units held by non-residents of Canada.

Critical accounting estimates

Provident's significant accounting policies are described in note 2 to the consolidated financial statements. Certain accounting policies include critical accounting estimates. These policies require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain. These accounting policies could result in materially different results should the underlying assumptions or conditions change.

Management assumptions are based on Provident's historical experience, management's experience, and other factors that, in management's opinion, are relevant and appropriate. Management assumptions may change over time, as further experience is gained or as operating conditions change.

The Trust's financial and operating results incorporate certain estimates including:

- depletion, depreciation and accretion based on estimated oil and gas reserves;
- future recoverable value of property, plant and equipment and goodwill (see "Goodwill") based on estimated future cash flows;
- value of asset retirement obligations based on estimated future costs and timing of expenditures;
- fair values of derivative contracts that are subject to fluctuation depending upon underlying commodity prices and foreign exchange rates (see note 13 to the consolidated financial statements); and
- income taxes based on estimates of future income and tax pool claims (see "Taxes").

Property, plant and equipment

Provident follows the full cost method of accounting, whereby all costs associated with the acquisition and development of oil and natural gas reserves are capitalized. Utilization of the full cost method of accounting requires the use of management estimates and assumptions for amounts recorded for depletion and depreciation of property, plant and equipment as well as for the ceiling test.

The provision for depletion and depreciation is calculated using the unit of production method based on current production divided by Provident's share of estimated total proved oil and natural gas reserve volumes before royalties. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre. If the carrying value is not recoverable the cost centre is written down to its fair value.

Proved reserves are an estimate, under existing reserve evaluation policies, of volumes that can reasonably be expected to be economically recoverable under existing technology and economic conditions. Changes in underlying assumptions or economic conditions could have a material impact on Provident's financial results. To mitigate these risks, management utilizes McDaniel & Associates Consultants Ltd. and AJM Petroleum Consultants, independent engineering firms, to evaluate Provident's reserves.

Estimates of future production, oil and natural gas prices and future costs used in the ceiling test are, by their very nature, subject to uncertainty and changes in underlying assumptions could have a material impact on Provident's financial results.

Asset retirement obligation

Under the asset retirement obligation (ARO) standard, the fair value of asset retirement obligations is recorded as a liability on a discounted basis, when incurred. The value of the related assets is increased by the same amount as the liability and depreciated over the useful life of the asset. Over time the liability is adjusted for the change in present value of the liability or as a result of changes to either the timing or amount of the original estimate of undiscounted future cash flows.

Asset retirement obligation requires that management make estimates and assumptions regarding future liabilities and cash flows involving environmental reclamation and remediation. Such assumptions are inherently uncertain and subject to change over time due to factors such as historical experience, changes in environmental legislation or improved technologies. Changes in underlying assumptions, based on the above noted factors, could have a material impact on Provident's financial results.

Change in accounting policies

(i) Inventory

In the first quarter of 2008, the Trust adopted the new accounting standard, CICA Handbook Section 3031 - Inventories, which replaced the previous standard for inventories, Section 3030. The main features of the new Section are as follows:

- measurement of inventories at the lower of cost and net realizable value;
- consistent use of either first-in, first-out or a weighted average cost formula to measure cost;
- reversal of previous write-downs to net realizable value when there is a subsequent increase to the value of inventories.

Adoption of the new Section has not had a material impact on the consolidated financial statements.

(ii) Capital disclosures

In the first quarter of 2008, the Trust adopted CICA Handbook Section 1535 “Capital Disclosures” which addresses the requirements for an entity to disclose qualitative information about its objectives, policies and processes for managing capital. This section also establishes the requirement for an entity to disclose quantitative data about what it regards as capital as well as disclose whether it has complied with any externally imposed capital requirements and, if not, the consequences of such non-compliance. The new disclosure is included in note 14.

(iii) Financial instruments – disclosures

In the first quarter of 2008, the Trust adopted CICA Handbook Section 3862 “Financial Instruments-Disclosures” and Section 3863 “Financial Instruments-Presentation”. Section 3862 requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity’s financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks. Section 3863 establishes presentation guidelines for financial instruments and non-financial derivatives and addresses the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and circumstances in which financial assets and financial liabilities are offset. The new disclosure is included in note 13.

(iv) International Financial Reporting Standards (IFRS)

During 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) in place of Canadian GAAP for interim and annual reporting purposes. The required changeover date is for fiscal years beginning on or after January 1, 2011.

Provident has commenced the process to transition from current Canadian GAAP to IFRS. It has established a project plan and a project team. The project team is led by finance management and includes representatives from various areas of the organization as necessary to plan for a smooth transition to IFRS.

The project plan consists of three phases: initiation, detailed assessment and design and implementation. Provident has completed the first phase, which involved the development of a detailed timeline for assessing resources and training and the completion of a high level review of the major differences between current Canadian GAAP and IFRS. Education and training sessions for employees throughout the organization and discussions with Provident’s external auditors have commenced and will continue throughout the subsequent phases. Regular reporting is provided to Provident’s senior management and to the Audit Committee of the Board of Directors.

Provident is currently engaged in the detailed assessment and design phase of the project. The detailed assessment and design phase involves established work teams to complete a comprehensive analysis of the

impact of the IFRS differences identified in the initial scoping assessment. In addition, an initial evaluation of IFRS 1 transition exemptions and an analysis of financial systems has commenced.

During the implementation phase, Provident will execute the required changes to business processes, financial systems, accounting policies, disclosure controls and internal controls over financial reporting. At this time, the impact on the consolidated financial statements is not reasonably determinable.

For recent accounting pronouncements, see note 3 to consolidated financial statements.

Business risks

The trust industry is subject to risks that can affect the amount of funds flow from operations available for distribution to unitholders, and the ability to grow. These risks include but are not limited to:

- capital markets, credit and liquidity risks and the ability to finance future growth; and
- the impact of Canadian governmental regulation on Provident, including the effect of the new tax on trust distributions.

The oil and natural gas industry is subject to numerous risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- fluctuations in commodity price, exchange rates and interest rates;
- government and regulatory risk in respect of royalty and income tax regimes;
- changes to environmental regulations;
- operational risks that may affect the quality and recoverability of reserves;
- geological risk associated with accessing and recovering new quantities of reserves;
- transportation risk in respect of the ability to transport oil and natural gas to market;
- marketability of oil and natural gas;
- the ability to attract and retain employees; and
- environmental, health and safety risks.

The midstream industry is also subject to risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- operational matters and hazards including the breakdown or failure of equipment, information systems or processes, the performance of equipment at levels below those originally intended, operator error, labour disputes, disputes with owners of interconnected facilities and carriers and catastrophic events such as natural disasters, fires, explosions, fractures, acts of eco-terrorists and saboteurs, and other similar events, many of which are beyond the control of the Trust or Provident;
- the Midstream NGL assets are subject to competition from other gas processing plants, and the pipelines and storage, terminal and processing facilities are also subject to competition from other pipelines and storage, terminal and processing facilities in the areas they serve, and the gas products marketing business is subject to competition from other marketing firms;
- exposure to commodity price fluctuations;
- the ability to attract and retain employees;
- regulatory intervention in determining processing fees and tariffs; and
- reliance on significant customers.

Provident strives to minimize these business risks by:

- employing and empowering management and technical staff with extensive industry experience and providing competitive remuneration;
- adhering to a strategy of acquiring, developing and optimizing quality, low-risk reserves in areas where we have technical and operational expertise;
- developing a diversified, balanced asset portfolio that generally offers developed operational infrastructure, year-round access and close proximity to markets;
- adhering to a disciplined Commodity Price Risk Management Program to mitigate the impact that volatile commodity prices have on cash flow available for distribution;
- marketing crude oil and natural gas to a diverse group of customers, including aggregators, industrial users, well-capitalized third-party marketers and spot market buyers;
- marketing natural gas liquids and related services to selected, credit worthy customers at competitive rates;
- maintaining a competitive cost structure to maximize cash flow and profitability;
- maintaining prudent financial leverage and developing strong relationships with the investment community and capital providers;
- adhering to strict guidelines and reporting requirements with respect to environmental, health and safety practices; and
- maintaining an adequate level of property, casualty, comprehensive and directors' and officers' insurance coverage.

Readers should be aware that the risks set forth herein are not exhaustive. Readers are referred to Provident's annual information form, which is available at www.sedar.com, for a detailed discussion of risks affecting Provident.

Unit trading activity

The following table summarizes the unit trading activity of the Provident units for each of the four quarters in the year ended December 31, 2008 on both the Toronto Stock Exchange and the New York Stock Exchange:

	Q1	Q2	Q3	Q4
TSE – PVE.UN (Cdn\$)				
High	\$ 11.37	\$ 12.25	\$ 11.66	\$ 9.55
Low	\$ 8.80	\$ 10.76	\$ 8.71	\$ 4.68
Close	\$ 10.95	\$ 11.74	\$ 9.50	\$ 5.35
Volume (000s)	34,702	28,161	26,269	31,780
NYSE – PVX (US\$)				
High	\$ 11.28	\$ 12.40	\$ 11.50	\$ 9.00
Low	\$ 8.50	\$ 10.50	\$ 8.50	\$ 3.64
Close	\$ 10.60	\$ 11.43	\$ 8.98	\$ 4.36
Volume (000s)	74,533	77,141	76,617	147,340

Forward-looking information

This MD&A contains forward-looking information under applicable securities legislation. Statements which include forward-looking information relate to future events or the Trust's future performance. Such forward-looking information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. All statements other than statements of historical fact are forward-looking information. In some cases, forward-looking information can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. Statements relating to "reserves" or "resources" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Forward looking information in this MD&A includes, but is not limited to, business strategy and objectives, reserve quantities and the discounted present value of future net cash flows from such reserves, net revenue, future production levels, capital

expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, royalty rates, budgeted levels of cash distributions and the performance associated with Provident's natural gas midstream, NGL processing and marketing business. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual events or results to differ materially from those anticipated by the Trust and described in the forward-looking information. In addition, this MD&A may contain forward-looking information attributed to third party industry sources. Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking information will not occur. Forward-looking information in this MD&A includes, but is not limited to, statements with respect to:

- the Trust's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets;
- the Trust's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- sustainability and growth of production and reserves through prudent management and acquisitions;
- the emergence of accretive growth opportunities;
- the ability to achieve an appropriate level of monthly cash distributions;
- the impact of Canadian governmental regulation on the Trust;
- the existence, operation and strategy of the commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed;
- changes in oil and natural gas prices and the impact of such changes on cash flow after financial derivative instruments;
- the level of capital expenditures devoted to development activity rather than exploration;
- the sale, farming out or development using third party resources to exploit or produce certain exploration properties;
- the use of development activity and acquisitions to replace and add to reserves;
- the quantity of oil and natural gas reserves and oil and natural gas production levels;
- currency, exchange and interest rates;
- the performance characteristics of Provident's midstream, NGL processing and marketing business;
- the growth opportunities associated with the midstream, NGL processing and marketing business; and
- the nature of contractual arrangements with third parties in respect of Provident's midstream, NGL processing and marketing business.

Although the Trust believes that the expectations reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. The Trust can not guarantee future results, levels of activity, performance, or achievements. Moreover, neither the Trust nor any other person assumes responsibility for the accuracy and completeness of the forward-looking information. Some of the risks and other factors, some of which are beyond the Trust's control, which could cause results to differ materially from those expressed in the forward-looking information contained in this MD&A include, but are not limited to:

- general economic and credit conditions in Canada, the United States and globally;
- industry conditions associated with the NGL services, processing and marketing business;
- fluctuations in the price of crude oil, natural gas and natural gas liquids;
- uncertainties associated with estimating reserves;
- royalties payable in respect of oil and gas production;
- interest payable on notes issued in connection with acquisitions;
- income tax legislation relating to income trusts, including the effect of legislation taxing trust income;
- governmental regulation in North America of the oil and gas industry, including income tax and environmental regulation;
- fluctuation in foreign exchange or interest rates;
- stock market volatility and market valuations;
- the impact of environmental events;
- the need to obtain required approvals from regulatory authorities;
- unanticipated operating events which can reduce production or cause production to be shut-in or delayed;

- failure to realize the anticipated benefits of acquisitions;
- competition for, among other things, capital reserves, undeveloped lands and skilled personnel;
- failure to obtain industry partner and other third party consents and approvals, when required;
- risks associated with foreign ownership;
- third party performance of obligations under contractual arrangements; and
- the other factors set forth under "Business risks" in this MD&A.

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties. With respect to developing forward-looking information contained in this MD&A, the Trust has made assumptions regarding, among other things:

- future natural gas and crude oil prices;
- the ability of the Trust to obtain qualified staff and equipment in a timely and cost-efficient manner to meet demand;
- the regulatory framework regarding royalties, taxes and environmental matters in which the Trust conducts its business;
- the impact of increasing competition;
- the Trust's ability to obtain financing on acceptable terms;
- the general stability of the economic and political environment in which the Trust operates;
- the timely receipt of any required regulatory approvals;
- the ability of the operator of the projects which the Trust has an interest in to operate the field in a safe, efficient and effective manner;
- field production rates and decline rates;
- the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration;
- the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Trust to secure adequate product transportation;
- currency, exchange and interest rates; and
- the ability of the Trust to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. Forward-looking information contained in this MD&A is made as of the date hereof and the Trust undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

Additional information

Additional information concerning Provident can be accessed under Provident's public filings at www.sedar.com and www.sec.gov/edgar.shtml, as well as on Provident's website at www.providentenergy.com.

Selected annual financial measures

(\$ 000s except per unit data)	2008	2007	2006
Revenue from continuing operations (net of royalties and financial derivative instruments)	\$ 3,239,163	\$ 2,038,515	\$ 2,023,178
Net income	157,392	30,434	140,920
Net income per unit - basic and diluted	0.62	0.13	0.72
Total assets	3,074,069	5,758,792	3,370,919
Long-term financial liabilities from continuing operations ⁽¹⁾	867,232	1,382,921	1,065,932
Declared distributions per unit.	\$ 1.38	\$ 1.44	\$ 1.44

⁽¹⁾ Includes long-term debt, asset retirement obligation, long-term financial derivative instruments and other long-term liabilities.

Quarterly table

Segmented information by quarter

(\$ 000s except for per unit and operating amounts)

	2008				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual Total
Financial - consolidated					
Revenue (continuing operations)	\$ 702,215	\$ 420,220	\$ 1,097,408	\$ 1,019,320	\$ 3,239,163
Funds flow from operations	\$ 180,230	\$ 241,487	\$ 151,661	\$ 81,779	\$ 655,157
Net income (loss)	\$ 33,616	\$ (184,081)	\$ 351,105	\$ (43,248)	\$ 157,392
Net income (loss) per unit - basic	\$ 0.13	\$ (0.72)	\$ 1.37	\$ (0.17)	\$ 0.62
Net income (loss) per unit - diluted	\$ 0.13	\$ (0.72)	\$ 1.29	\$ (0.17)	\$ 0.62
Unitholder distributions	\$ 91,117	\$ 91,662	\$ 92,188	\$ 77,324	\$ 352,291
Distributions per unit	\$ 0.36	\$ 0.36	\$ 0.36	\$ 0.30	\$ 1.38
Oil and gas production (continuing operations)					
Cash revenue	\$ 122,815	\$ 164,442	\$ 158,400	\$ 101,437	\$ 547,094
Earnings before interest, DD&A, taxes and other non-cash items	\$ 75,348	\$ 117,132	\$ 111,256	\$ 49,757	\$ 353,493
Funds flow from operations	\$ 71,142	\$ 112,869	\$ 107,442	\$ 47,187	\$ 338,640
Net income (loss)	\$ 9,591	\$ 28,935	\$ 76,881	\$ (421,457)	\$ (306,050)
Provident Midstream					
Cash revenue	\$ 641,673	\$ 662,315	\$ 652,753	\$ 513,860	\$ 2,470,601
Earnings before interest, DD&A, taxes and other non-cash items	\$ 75,987	\$ 61,769	\$ 37,339	\$ 37,666	\$ 212,761
Funds flow from operations	\$ 59,252	\$ 52,601	\$ 32,537	\$ 34,592	\$ 178,982
Net income (loss)	\$ 15,516	\$ (290,230)	\$ 232,966	\$ 359,166	\$ 317,418
Operating					
Oil and gas production (continuing operations)					
Light/medium oil (bpd)	10,535	10,179	10,109	9,885	10,176
Heavy oil (bpd)	1,752	2,315	2,696	2,422	2,297
Natural gas liquids (bpd)	1,307	1,178	1,195	1,134	1,203
Natural gas (mcf)	83,970	86,130	85,628	80,450	84,039
Oil equivalent (boed)	27,589	28,027	28,271	26,849	27,683
Average selling price net of transportation expense (continuing operations) (Cdn\$)					
Crude oil per bbl (before realized financial derivative instruments)	\$ 75.06	\$ 105.13	\$ 102.66	\$ 47.33	\$ 82.79
Crude oil per bbl (including realized financial derivative instruments)	\$ 71.54	\$ 98.68	\$ 97.61	\$ 52.71	\$ 80.36
Natural gas liquids per barrel	\$ 72.85	\$ 94.59	\$ 91.72	\$ 47.64	\$ 76.88
Natural gas per mcf (before realized financial derivative instruments)	\$ 7.61	\$ 9.98	\$ 8.60	\$ 6.63	\$ 8.23
Natural gas per mcf (including realized financial derivative instruments)	\$ 7.74	\$ 9.73	\$ 8.45	\$ 6.92	\$ 8.23
Provident Midstream					
Provident Midstream NGL sales volumes (bpd)	136,320	110,826	111,313	120,222	119,649

Quarterly table

Segmented information by quarter

(\$ 000s except for per unit and operating amounts)

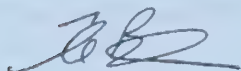
	2007				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual Total
Financial - consolidated					
Revenue (continuing operations)	\$ 558,807	\$ 463,995	\$ 494,065	\$ 521,648	\$ 2,038,515
Funds flow from operations	\$ 87,040	\$ 98,503	\$ 105,149	\$ 177,563	\$ 468,255
Net income (loss)	\$ 43,093	\$ (46,199)	\$ (35,005)	\$ 68,545	\$ 30,434
Net income (loss) per unit - basic and diluted	\$ 0.20	\$ (0.21)	\$ (0.14)	\$ 0.28	\$ 0.13
Unitholder distributions	\$ 76,271	\$ 80,236	\$ 87,782	\$ 89,063	\$ 333,352
Distributions per unit	\$ 0.36	\$ 0.36	\$ 0.36	\$ 0.36	\$ 1.44
Oil and gas production (continuing operations)					
Cash revenue	\$ 84,668	\$ 90,028	\$ 92,419	\$ 101,746	\$ 368,861
Earnings before interest, DD&A, taxes and other non-cash items	\$ 49,756	\$ 55,457	\$ 53,530	\$ 63,009	\$ 221,752
Funds flow from operations	\$ 46,410	\$ 52,032	\$ 47,143	\$ 58,667	\$ 204,252
Net (loss) income	\$ (4,510)	\$ 50,429	\$ (17,807)	\$ 16,953	\$ 45,065
Provident Midstream					
Cash revenue	\$ 453,272	\$ 397,713	\$ 433,950	\$ 598,963	\$ 1,883,898
Earnings before interest, DD&A, taxes and other non-cash items	\$ 52,853	\$ 35,974	\$ 47,425	\$ 89,423	\$ 225,675
Funds flow from operations	\$ 39,404	\$ 29,569	\$ 32,350	\$ 77,109	\$ 178,432
Net income (loss)	\$ 51,838	\$ (142,191)	\$ (8,630)	\$ (62,037)	\$ (161,020)
Operating					
Oil and gas production (continuing operations)					
Light/medium oil (bpd)	6,428	6,692	8,858	9,483	7,876
Heavy oil (bpd)	1,669	1,918	2,324	1,769	1,921
Natural gas liquids (bpd)	1,422	1,311	1,255	1,277	1,316
Natural gas (mcf)	88,928	94,437	93,511	92,584	92,378
Oil equivalent (boed)	24,340	25,660	28,022	27,960	26,509
Average selling price net of transportation expense (continuing operations) (Cdn\$)					
Crude oil per bbl (before realized financial derivative instruments)	\$ 51.23	\$ 53.75	\$ 57.88	\$ 61.75	\$ 56.74
Crude oil per bbl (including realized financial derivative instruments)	\$ 51.25	\$ 52.77	\$ 55.47	\$ 57.23	\$ 54.53
Natural gas liquids per barrel	\$ 49.02	\$ 52.79	\$ 55.47	\$ 63.63	\$ 55.07
Natural gas per mcf (before realized financial derivative instruments)	\$ 7.48	\$ 7.27	\$ 4.94	\$ 6.08	\$ 6.42
Natural gas per mcf (including realized financial derivative instruments)	\$ 7.37	\$ 7.20	\$ 5.63	\$ 6.68	\$ 6.71
Provident Midstream					
Provident Midstream NGL sales volumes (bpd)	125,033	109,713	112,386	135,981	120,785

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Provident is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2008, our internal control over financial reporting was effective.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of the Trust's internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report which appears herein.



Thomas W. Buchanan
Chief Executive Officer



Mark N. Walker
Chief Financial Officer

Calgary, Alberta
March 11, 2009

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Provident is responsible for the information included in this Annual Report. The financial statements have been prepared in accordance with accounting principles generally accepted in Canada and in accordance with accounting policies detailed in the notes to the financial statements. Where necessary, the statements include amounts based on management's informed judgments and estimates. Financial information in the Annual Report is consistent with that presented in the financial statements.

PricewaterhouseCoopers LLP, Chartered Accountants, appointed by the unitholders, have audited the financial statements and conducted a review of internal accounting policies and procedures to the extent required by generally accepted auditing standards, and performed such tests as they deemed necessary to enable them to express an opinion on the financial statements.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Audit Committee is composed of three independent directors. The Audit Committee reviews the financial content of the Annual Report and reports its findings to the Board of Directors for its consideration in approving the financial statements.



Thomas W. Buchanan
Chief Executive Officer



Mark N. Walker
Chief Financial Officer

Calgary, Alberta
March 11, 2009

Independent Auditors' Report

PricewaterhouseCoopers LLP
Chartered Accountants
 111 5 Avenue SW, Suite 3100
 Calgary, Alberta
 Canada T2P 5L3
 Telephone +1 403 509 7500
 Facsimile +1 403 781 1825

To the Unitholders of Provident Energy Trust

We have completed integrated audits of Provident Energy Trust's (the "Trust") 2008 and 2007 consolidated financial statements and of its internal control over financial reporting as at December 31, 2008. Our opinions, based on our audits, are presented below.

Consolidated Financial statements

We have audited the accompanying consolidated balance sheets of Provident Energy Trust as at December 31, 2008 and December 31, 2007, and the related consolidated statements of operations and accumulated income, comprehensive and accumulated other comprehensive income and cash flows for each of the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits of the Trust's consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Trust as at December 31, 2008 and December 31, 2007 and the results of its operations and its cash flows for each of the years then ended in accordance with Canadian generally accepted accounting principles.

Internal control over financial reporting

We have also audited Provident Energy Trust's internal control over financial reporting as at December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as at December 31, 2008 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
March 11, 2009

PROVIDENT ENERGY TRUST
CONSOLIDATED BALANCE SHEETS

Canadian dollars (000s)

	As at December 31, 2008	As at December 31, 2007
Assets		
Current assets		
Cash and cash equivalents	\$ 4,629	\$ -
Accounts receivable	244,485	338,105
Petroleum product inventory	46,160	84,638
Prepaid expenses and other current assets	7,886	8,313
Financial derivative instruments (note 13)	16,708	1,329
Assets held for sale - USOGP (note 15)	-	93,578
	319,868	525,963
Investments and other long term assets	14,218	5,862
Long-term financial derivative instruments (note 13)	735	-
Property, plant and equipment (note 5)	2,480,503	2,510,271
Intangible assets (note 6)	158,336	171,793
Goodwill (note 7)	100,409	517,299
Assets held for sale - USOGP (note 15)	-	2,027,604
	\$ 3,074,069	\$ 5,758,792
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	\$ 244,031	\$ 347,224
Cash distributions payable	20,088	25,100
Current portion of convertible debentures (note 8)	24,871	19,198
Financial derivative instruments (note 13)	13,693	130,276
Liabilities held for sale - USOGP (note 15)	-	114,681
	302,683	636,479
Long-term debt - revolving term credit facility (note 8)	504,685	923,996
Long-term debt - convertible debentures (note 8)	236,123	256,440
Asset retirement obligation (note 9)	59,432	43,886
Long-term financial derivative instruments (note 13)	58,420	146,199
Other long-term liabilities (note 11)	8,572	12,400
Future income taxes (note 12)	267,807	302,089
Liabilities held for sale - USOGP (note 15)	-	628,502
Non-controlling interests (note 15)		
Discontinued operations (USOGP)	-	1,100,136
Unitholders' equity		
Unitholders' contributions (note 10)	2,806,071	2,750,374
Convertible debentures equity component	17,198	18,213
Contributed surplus (note 11)	1,695	801
Accumulated other comprehensive loss	(2,183)	(69,188)
Accumulated income	426,034	268,642
Accumulated cash distributions	(1,612,468)	(1,260,177)
	1,636,347	1,708,665
	\$ 3,074,069	\$ 5,758,792

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board of Directors:



M.H. (Mike) Shaikh, FCA
Director



Thomas W. Buchanan, CA
Director

PROVIDENT ENERGY TRUST**CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED INCOME**

Canadian dollars (000s except per unit amounts)

	Year ended December 31,	
	2008	2007
Revenue		
Revenue	\$ 3,147,714	\$ 2,325,505
Realized loss on financial derivative instruments	(130,019)	(72,746)
Unrealized gain (loss) on financial derivative instruments	221,468	(214,244)
	3,239,163	2,038,515
Expenses		
Cost of goods sold	2,206,427	1,594,639
Production, operating and maintenance	153,111	126,481
Transportation	37,120	25,018
Depletion, depreciation and accretion	343,315	301,111
Goodwill impairment (note 7)	416,890	-
General and administrative (note 11)	66,913	62,353
Interest on bank debt	36,088	44,221
Interest and accretion on convertible debentures	19,944	14,687
Foreign exchange (gain) loss and other	(20,828)	4,202
	3,258,980	2,172,712
Loss from continuing operations before taxes	(19,817)	(134,197)
Capital tax expense	3,109	3,762
Current and withholding tax (recovery) expense	(4,529)	6,352
Future income tax recovery (note 12)	(29,765)	(28,356)
	(31,185)	(18,242)
Net income (loss) from continuing operations	11,368	(115,955)
Net income from discontinued operations (note 15)	146,024	146,389
Net income	157,392	30,434
Accumulated income, beginning of year	\$ 268,642	\$ 238,208
Accumulated income, end of year	\$ 426,034	\$ 268,642
Net income (loss) from continuing operations per unit		
– basic and diluted	\$ 0.04	\$ (0.50)
Net income per unit		
– basic and diluted	\$ 0.62	\$ 0.13

The accompanying notes to the consolidated financial statements are an integral part of these statements.

PROVIDENT ENERGY TRUST
CONSOLIDATED STATEMENT OF CASH FLOWS

Canadian dollars (000s)

	Year ended December 31,	
	2008	2007
Cash provided by operating activities		
Net income (loss) for the year from continuing operations	\$ 11,368	\$ (115,955)
Add (deduct) non-cash items:		
Depletion, depreciation and accretion	343,315	301,111
Goodwill impairment (note 7)	416,890	-
Non-cash interest expense and other	5,291	2,797
Non-cash unit based compensation (recovery) expense (note 11)	(4,117)	8,064
Unrealized (gain) loss on financial derivative instruments	(221,468)	214,244
Unrealized foreign exchange (gain) loss and other	(3,892)	779
Future income tax recovery (note 12)	(29,765)	(28,356)
Funds flow from continuing operations	517,622	382,684
Funds flow from discontinued operations	137,535	85,571
Funds flow from operations	655,157	468,255
Site restoration expenditures	(6,381)	(4,062)
Change in non-cash operating working capital from continuing operations	52,684	4,807
Change in non-cash operating working capital from discontinued operations	(27,034)	(4,545)
	674,426	464,455
Cash (used for) provided by financing activities		
(Decrease) increase in long-term debt	(440,244)	169,122
Declared distributions to unitholders	(352,291)	(333,352)
Issue of trust units, net of issue costs	55,510	412,909
Change in non-cash financing working capital	(5,028)	2,856
Financing activities from discontinued operations	(47,511)	1,011,670
	(789,564)	1,263,205
Cash provided by (used for) investing activities		
Capital expenditures	(246,947)	(178,113)
Capitol Energy acquisition (note 4)	-	(467,495)
Triwest Energy acquisition (note 4)	-	(2,300)
Oil and gas property acquisitions	(24,181)	(13,050)
Increase in investments	(792)	(5,450)
Proceeds on sale of assets	-	7,624
Proceeds on sale of discontinued operations, net of tax (note 15)	457,906	-
Change in non-cash investing working capital	(3,229)	14,920
Investing activities from discontinued operations	(69,810)	(1,087,278)
	112,947	(1,731,142)
Decrease in cash and cash equivalents	(2,191)	(3,482)
Cash and cash equivalents, beginning of year	6,820	10,302
Cash and cash equivalents, end of year	\$ 4,629	\$ 6,820
Cash and cash equivalents, end of year from discontinued operations	\$ -	\$ 6,820
Cash and cash equivalents, end of year from continuing operations	\$ 4,629	\$ -
Supplemental disclosure of cash flow information		
Cash interest paid including debenture interest	\$ 63,490	\$ 69,600
Cash taxes paid (note 15)	\$ 210,132	\$ 13,741

The accompanying notes to the consolidated financial statements are an integral part of these statements.

PROVIDENT ENERGY TRUST
CONSOLIDATED STATEMENT OF COMPREHENSIVE
AND ACCUMULATED OTHER COMPREHENSIVE INCOME
Canadian Dollars (000s)

	Year ended	
	December 31,	
	2008	2007
Net income	\$ 157,392	\$ 30,434
Other comprehensive income (loss), net of taxes		
Foreign currency translation adjustments	10,315	(25,083)
Reclassification adjustment for foreign currency losses included in net income	57,062	-
Unrealized loss on available-for-sale investments (net of taxes)	(372)	(1,811)
	67,005	(26,894)
Comprehensive income	\$ 224,397	\$ 3,540
Accumulated other comprehensive loss, beginning of year	(69,188)	(42,294)
Other comprehensive income (loss)	67,005	(26,894)
Accumulated other comprehensive loss, end of year	\$ (2,183)	\$ (69,188)
Accumulated income, end of year	426,034	268,642
Accumulated cash distributions, end of year	(1,612,468)	(1,260,177)
Retained earnings (deficit), end of year	(1,186,434)	(991,535)
Accumulated other comprehensive loss, end of year	(2,183)	(69,188)
Total retained earnings (deficit) and accumulated other comprehensive loss, end of year	\$ (1,188,617)	\$ (1,060,723)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

< 60

(Tabular amounts in Cdn \$ 000's, except unit and per unit amounts)

December 31, 2008

1. Structure of the Trust

Provident Energy Trust (the "Trust" or "Provident") is an open-end unincorporated investment trust created under the laws of Alberta pursuant to a trust indenture dated January 25, 2001, amended from time to time. The beneficiaries of the Trust are the unitholders. The Trust was established to hold, directly and indirectly, all types of petroleum and natural gas and energy related assets, including without limitation facilities of any kind, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets. The Trust commenced operations March 6, 2001.

Cash flow is provided to the Trust from properties owned and operated by Provident Energy Ltd. and other directly and indirectly owned subsidiaries of the Trust. Cash flow is paid to the Trust by way of royalty payments, interest payments and principal debt repayments. The cash payments received by the Trust are subsequently distributed to the unitholders monthly.

2. Significant accounting policies

i) Principles of consolidation and investments

The consolidated financial statements include the accounts of the Trust, including the consolidated accounts of all wholly and partially owned subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles. Investments subject to significant influence are accounted for using the equity method. Certain comparative figures have been reclassified to conform to the current year presentation. In particular, the comparative figures have been reclassified to reflect discontinued operations presentation for the United States oil and natural gas production (USOGP) business (see note 15).

ii) Financial instruments

All financial instruments, including derivatives, are recognized on the Trust's Consolidated Balance Sheet. Derivatives are measured at fair value with unrealized gains and losses reported in net income. Investments, other than investments accounted for by the equity method, are measured at fair value, with reference to published price quotations, and unrealized gains and losses are reported in AOCI. The Trust's other financial instruments (accounts receivable, accounts payable and accrued liabilities, cash distributions payable, and long-term debt) are measured at amortized cost using the effective interest rate method. Transaction costs are included with the associated financial instruments and amortized accordingly (see note 3).

iii) Cash and cash equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less when purchased.

iv) Property, plant & equipment and intangible assets

The Trust follows the full cost method of accounting for oil and natural gas exploration and development activities, whereby all costs associated with the acquisition and development of oil and natural gas reserves are capitalized. Such costs include lease acquisition, lease rentals on non-producing properties, geological and geophysical activities, drilling of productive and non-productive wells, and tangible well equipment. Gains or losses on the disposition of oil and gas properties are not recognized unless the resulting change to

the depletion and depreciation rate is 20 percent or more. All other property, plant and equipment, including midstream assets, are recorded at cost. Expenditures relating to renewals or betterments that improve the productive capacity or extend the life of property, plant and equipment are capitalized. Maintenance and repairs are expensed as incurred. Products required for line-fill and cavern bottoms are presented as part of property, plant and equipment and are stated at the lower of historic cost and net realizable value and are not depreciated.

a) Depletion, depreciation and accretion

The provision for depletion and depreciation for oil and natural gas assets is calculated, by cost centre, using the unit-of-production method based on current production divided by the Trust's share of estimated total proved oil and natural gas reserve volumes, before royalties. Production and reserves of natural gas and associated liquids are converted at the energy equivalent ratio of 6,000 cubic feet of natural gas to one barrel of oil. In determining its depletion base, the Trust includes estimated future costs for developing proved reserves, and excludes estimated salvage values of tangible equipment and the cost of unproved properties.

Midstream facilities, including natural gas liquids storage facilities and natural gas liquids processing and extraction facilities are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 30 to 40 years. Intangible assets are amortized over the estimated useful lives of the assets, which range from 12 to 15 years. Capital assets related to pipelines and office equipment are carried at cost and depreciated using the straight-line method over their economic lives.

b) Impairment

Oil and natural gas assets accounted for using the full cost method are subject to a ceiling test. The ceiling test calculation is performed by comparing the carrying value of the cost centre to the sum of the undiscounted proved reserve cash flows expected from the cost centre by country using future price estimates. If the carrying value is not recoverable, the cost centre is written down to its fair value. Fair value is determined by the future cash flows from the proved plus probable reserves discounted at the Trust's risk free interest rate. Any excess carrying value of the assets on the balance sheet above fair value would be recorded in depletion, depreciation and accretion expense as a permanent impairment.

For Midstream property, plant and equipment, and intangible assets, an impairment loss is recognized when the carrying amount exceeds the fair value.

v) Joint venture

Provident conducts many of its activities through joint ventures and the accounts reflect only Provident's proportionate interest in such activities.

vi) Inventory

Inventories of products are valued at the lower of average cost and net realizable value based on market prices.

vii) Goodwill

Goodwill, which represents the excess of cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed, is assessed at least annually for impairment. To assess impairment, the fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impaired amount. Goodwill is not amortized.

viii) Asset retirement obligation

Under the asset retirement obligation ("ARO") standard the fair value of a liability for an ARO is recorded in the period where a reasonable estimate of the fair value can be determined. When the liability is recorded, the carrying amount of the related asset is increased by the same amount of the liability. The asset recorded is depleted over the useful life of the asset. Additions to asset retirement obligations due to the passage of time are recorded as accretion expense. Actual expenditures incurred are charged against the obligation.

ix) Unit based compensation

The Trust uses the fair value method of valuing compensation expense associated with the Trust's unit option plan. Provident has applied this method to options issued after January 1, 2003, the effective date for implementing stock based compensation. Under the fair value method the amount to be recognized as expense is determined at the time the options are issued and is recognized in earnings over the vesting period of the options with a corresponding increase in contributed surplus.

The Trust has established other unit based compensation plans whereby notional units are granted to employees. The fair value of these notional units is estimated and recorded as non-cash unit based compensation (a component of general and administrative expenses). A portion relating to operational employees at field and plant locations is allocated to operating expense. The offsetting amount is recorded as accrued liabilities or other long-term liabilities. A realization of the expense and a resulting reduction in cash provided by operating activities occurs when a cash payment is made.

x) Trust unit calculations

The Trust applies the treasury stock method to determine the dilutive effect of trust unit rights and trust unit options. Under the treasury stock method, outstanding and exercisable instruments that will have a dilutive effect are included in per unit - diluted calculations, ordered from most dilutive to least dilutive.

The dilutive effect of convertible debentures is determined using the "if-converted" method whereby the outstanding debentures at the end of the period are assumed to have been converted at the beginning of the period or at the time of issue if issued during the year. Amounts charged to income or loss relating to the outstanding debentures are added back to net income for the diluted calculation. The units issued upon conversion are included in the denominator of per unit - basic calculations from the date of issue.

xi) Income taxes

Provident follows the liability method for calculating income taxes. Differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases are applied to tax rates in effect to calculate the future tax liability. The effect of any change in income tax rates is recognized in the current period income.

The Trust is a taxable entity under the Income Tax Act (Canada) and is currently taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for current income taxes has been made in the Trust.

In 2007, the Canadian government enacted Bill C-52, Budget Implementation Act 2007. This bill contains legislation to tax publicly traded trusts, commencing in 2011. As a result of this legislation, the Trust records the future income tax effect of the temporary differences on its flow through entities that are expected to reverse subsequent to 2010.

xii) Revenue recognition

Revenue associated with the sales of Provident's natural gas, natural gas liquids ("NGLs") and crude oil owned by Provident is recognized when title passes from Provident to its customer.

Revenues associated with the services provided where Provident acts as agent are recorded on a net basis when the services are provided. Revenues associated with the sale of natural gas liquids storage services are recognized when the services are provided.

xiii) Foreign currency translation

The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenue and expenses are translated using average rates for the period. Translation gains and losses related to self-sustaining operations are deferred and included as a component of accumulated other comprehensive income. A proportionate amount of the gain or loss is recognized in net income when there has been a reduction in the net investment.

The accounts of integrated foreign operations are translated using the temporal method, under which monetary assets and liabilities are translated at the period-end exchange rate, other assets and liabilities at the historical rates, and revenues and expenses at the rates for the period, except depreciation, depletion and accretion which is translated on the same basis as the related assets. Translation gains and losses are included in income in the period in which they arise.

xiv) Use of estimates

The preparation of financial statements requires management to make estimates based on currently available information. Actual results could differ from those estimated. In particular, management makes estimates for amounts recorded for depletion and depreciation of the property, plant and equipment, financial derivative instruments, asset retirement obligation, unit based compensation and income taxes. The ceiling test uses factors such as estimated reserves, production rates, estimated future petroleum and natural gas prices and future costs. Due to the inherent limitations in metering and the physical properties of storage caverns and pipelines, the determination of precise volumes of natural gas liquids held in inventory at such locations is subject to estimation. Actual inventories of natural gas liquids can only be determined by draining of the caverns. By their very nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of future periods could be material.

The estimation of oil and gas reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity prices, and the timing of future expenditures. The Trust expects reserve estimates to be revised based on the results of future drilling activity, testing, production levels, and economics of recovery based on cash flow forecasts.

3. Changes in accounting policies and practices**A. Changes in accounting policies****(i) Inventory**

In the first quarter of 2008, the Trust adopted the new accounting standard, CICA Handbook Section 3031 - Inventories, which replaced the previous standard for inventories, Section 3030. The main features of the new Section are as follows:

- measurement of inventories at the lower of cost and net realizable value;
- consistent use of either first-in, first-out or a weighted average cost formula to measure cost;
- reversal of previous write-downs to net realizable value is required when there is a subsequent increase to the value of inventories.

Adoption of the new Section has not had a material impact on the consolidated financial statements.

(ii) Capital disclosures

In the first quarter of 2008, the Trust adopted CICA Handbook Section 1535 “Capital Disclosures” which addresses the requirements for an entity to disclose qualitative information about its objectives, policies and processes for managing capital. This section also establishes the requirement for an entity to disclose quantitative data about what it regards as capital as well as disclose whether it has complied with any externally imposed capital requirements and, if not, the consequences of such non-compliance. The new disclosure is included in note 14.

(iii) Financial instruments – disclosures

In the first quarter of 2008, the Trust adopted CICA Handbook Section 3862 “Financial Instruments-Disclosures” and Section 3863 “Financial Instruments-Presentation”. Section 3862 requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity’s financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks. Section 3863 establishes presentation guidelines for financial instruments and non-financial derivatives and addresses the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and circumstances in which financial assets and financial liabilities are offset. The new disclosure is included in note 13.

B. Recent accounting pronouncements**i) Goodwill and intangible assets**

In February 2008, the CICA released section 3064 “Goodwill and Intangible assets” which supersedes section 3062 “Goodwill and other Intangible assets” and section 3450 “Research and Development”. This new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. This section applies to annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. The Trust does not expect the adoption of this standard to have a material impact on its consolidated financial statements.

ii) International Financial Reporting Standards

During 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) in place of Canadian GAAP for interim and annual reporting purposes. The required changeover date is for fiscal years beginning on or after January 1, 2011. At this time, the impact on the Trust’s consolidated financial statements is not reasonably determinable.

4. Acquisitions**i) Acquisition of Triwest**

On December 3, 2007, the Trust acquired the common shares of Triwest Energy Inc. (“Triwest”), for consideration of 6,251,149 trust units with an ascribed value of \$76.6 million plus acquisition costs of \$0.8 million and cash consideration of \$1.5 million. Triwest was a privately held company with oil assets primarily in southeast Saskatchewan. The transaction was accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed	
Property, plant and equipment	\$ 115,719
Working capital, net	(2,757)
Bank debt	(11,122)
Asset retirement obligation	(752)
Future income taxes	(22,211)
	\$ 78,877
Consideration	
Acquisition costs	\$ 800
Cash	1,500
	2,300
Trust units issued	76,577
	\$ 78,877

ii) Acquisition of Capitol

On June 19, 2007, the Trust acquired Capitol Energy Resources Ltd. ("Capitol") for cash consideration of \$467.5 million. Capitol was a public oil and gas exploration and production company active in the Western Canadian sedimentary basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed	
Property, plant and equipment	\$ 522,707
Goodwill	85,946
Working capital, net	17,108
Bank debt	(53,100)
Financial derivative instruments	(621)
Asset retirement obligation	(1,752)
Future income taxes	(102,793)
	\$ 467,495
Consideration	
Acquisition costs	\$ 1,115
Cash	466,380
	\$ 467,495

The Capitol acquisition was financed by the issuance of 29,313,727 trust units at \$12.75 per unit and Provident's credit facility.

5. Property, plant and equipment

		Accumulated depletion and depreciation		Net Book value		
Year ended December 31, 2008		Cost				
Oil and natural gas properties	\$	3,125,360	\$	1,411,997	\$	1,713,363
Midstream assets		827,172		87,674		739,498
Office equipment		44,678		17,036		27,642
Total	\$	3,997,210	\$	1,516,707	\$	2,480,503

		Accumulated depletion and depreciation		Net Book value		
Year ended December 31, 2007		Cost				
Oil and natural gas properties	\$	2,870,191	\$	1,116,281	\$	1,753,910
Midstream assets		790,434		63,763		726,671
Office equipment		40,936		11,246		29,690
Total	\$	3,701,561	\$	1,191,290	\$	2,510,271

Costs associated with unproved properties and major development projects excluded from costs subject to depletion as at December 31, 2008 totaled \$93.1 million (December 31, 2007 - \$137.7 million). Midstream assets include \$41.8 million (2007 - \$35.9 million) for products required for line-fill and cavern bottoms.

An impairment test calculation was performed on property, plant and equipment at December 31, 2008 in which the estimated undiscounted future net cash flows based on estimated future prices associated with the proved reserves exceeded the carrying amount of oil and gas property, plant and equipment for each cost centre.

The following table outlines prices used in the impairment test at December 31, 2008:

Year	Oil \$/bbl	Gas \$/mcf	NGL \$/bbl
2009	\$ 56.95	\$ 7.12	\$ 51.51
2010	\$ 64.13	\$ 7.37	\$ 59.63
2011	\$ 70.46	\$ 7.64	\$ 66.15
2012	\$ 76.25	\$ 7.92	\$ 71.46
2013	\$ 81.08	\$ 8.21	\$ 76.75
Thereafter ⁽¹⁾	2%	2%	2%

⁽¹⁾ Percentage change represents the increase in each year after 2013 to the end of the reserve life.

6. Intangible assets

December 31, 2008	Cost	Accumulated amortization	Net Book value
Midstream contracts and customer relationships	\$ 183,100	37,255	\$ 145,845
Other intangible assets - Midstream	16,308	3,817	12,491
Total	\$ 199,408	\$ 41,072	\$ 158,336

December 31, 2007	Cost	Accumulated amortization	Net Book value
Midstream contracts and customer relationships	\$ 183,100	\$ 25,049	\$ 158,051
Other intangible assets - Midstream	16,308	2,566	13,742
Total	\$ 199,408	\$ 27,615	\$ 171,793

7. Goodwill

Goodwill represents the excess of the cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed. As at December 31, 2007 Goodwill was comprised of \$416.9 million related to acquisitions in the Canadian oil and gas business and \$100.4 million resulted from the Midstream NGL Acquisition in 2005.

Goodwill is assessed for impairment at least annually, and if an impairment exists, it would be charged to income in the period in which the impairment occurs. The impairment test includes a comparison of the net book value of the Trust's assets, by reporting units, to the estimated fair value of the reporting unit. In 2008, Provident engaged the services of a third-party evaluator to assist in determining fair value. Valuation methodologies included discounted cash flow, a transaction-based approach and a market-based approach, using trading multiples. Goodwill is not amortized.

The Trust performed its annual goodwill impairment test in the fourth quarter of 2008 and determined that the fair value of the Canadian oil and gas production unit was lower than the respective carrying value, primarily due to increasing economic uncertainty in the global market and the resulting higher cost of capital assumptions.

in the valuation methodologies. Consequently, a goodwill impairment, amounting to \$416.9 million was recorded. The impairment test indicated that the fair value of the Midstream reporting unit was in excess of the respective carrying value, therefore no write down of midstream-related goodwill was required. At December 31, 2008 the goodwill balance of \$100.4 million is related entirely to the Provident Midstream reporting unit.

8. Long-term debt

	December 31, 2008	December 31, 2007
Revolving term credit facility	\$ 504,685	\$ 923,996
Convertible debentures	260,994	275,638
Current portion of convertible debentures	(24,871)	(19,198)
	236,123	256,440
Total	\$ 740,808	\$ 1,180,436

i) Revolving term credit facility

Provident has a \$1,125 million term credit facility (2007 - \$1,125 million) with a syndicate of banks secured by midstream assets and by its Canadian oil and gas properties. Provident may draw on the credit facility by way of Canadian prime rate loans, U.S. base rate loans, banker's acceptances, letters of credit or LIBOR loans. At December 31, 2008, \$504.9 million was drawn on this facility. Included in the carrying value at December 31, 2008 were financing costs of \$0.2 million.

The terms of the credit facility have a revolving three year period expiring on May 30, 2011.

At December 31, 2008 the effective interest rate of the outstanding credit facility was 3.3 percent (2007 - 5.6 percent). At December 31, 2008 Provident had \$35.2 million in letters of credit outstanding (2007 - \$31.6 million) that guarantee Provident's performance under certain commercial and other contracts.

ii) Convertible debentures

The Trust may elect to satisfy interest and principal obligations by the issue of trust units. For the year ended December 31, 2008, \$0.1 million of the face value of debentures were converted to trust units at the election of debenture holders (2007 - \$6.1 million). Upon maturity in 2008, the Trust repaid \$19.9 million to the holders of its 8.75 percent convertible debentures, and the balance of the equity component of the 8.75 percent convertible debentures, amounting to \$1.0 million, was transferred to contributed surplus. Included in the carrying value at December 31, 2008 were financing costs of \$4.7 million. The fair value of the convertible debentures at December 31, 2008 approximates the face value of the instruments. The following table details each outstanding convertible debenture.

Convertible Debentures	As at December 31, 2008		As at December 31, 2007			Conversion Price per unit ⁽²⁾
(\$000s except conversion pricing)	Carrying Value ⁽¹⁾	Face Value	Carrying Value ⁽¹⁾	Face Value	Maturity Date	
6.5% Convertible Debentures	\$ 143,212	\$ 149,980	140,515	\$ 149,980	April 30, 2011	14.75
6.5% Convertible Debentures	92,911	98,999	91,460	99,024	Aug. 31, 2012	13.75
8.0% Convertible Debentures	24,871	25,109	24,465	25,109	July 31, 2009	12.00
8.75% Convertible Debentures	-	-	19,198	19,931	Dec. 31, 2008	11.05
	\$ 260,994	\$ 274,088	\$ 275,638	\$ 294,044		

⁽¹⁾ Excluding equity component of convertible debentures

⁽²⁾ The debentures may be converted into trust units at the option of the holder of the debenture at the conversion price per unit

9. Asset retirement obligation

The Trust's asset retirement obligation is based on the Trust's net ownership in wells, facilities and the midstream assets and represents management's estimate of the costs to abandon and reclaim those wells, facilities and midstream assets as well as an estimate of the future timing of the costs to be incurred. Estimated cash flows have been discounted at the Trust's average credit-adjusted risk free rate of seven percent and an inflation rate of two percent has been estimated for future years.

The total undiscounted amount of future cash flows required to settle asset retirement obligations related to oil and gas operations is estimated to be \$348.5 million (2007 - \$310.7 million). Payments to settle oil and gas asset retirement obligations occur over the operating lives of the assets estimated to be over the next 51 years.

The total undiscounted amount of future cash flows required to settle the midstream asset retirement obligations is estimated to be \$166.1 million (2007 - \$166.1 million). The estimated costs include such activities as dismantling, demolition and disposal of the facilities as well as remediation and restoration of the surface land. Payments to settle the midstream asset retirement obligations are expected to occur subsequent to the closure of the facilities and related assets. Settlement of these obligations is expected to occur in 25 to 41 years.

(\$000s)	Year ended December 31,	
	2008	2007
Carrying amount, beginning of year	\$ 43,886	\$ 33,246
Acquisitions	-	2,504
Change in estimate	15,759	7,127
Increase in liabilities incurred during the year	1,729	2,221
Settlement of liabilities during the year	(6,381)	(4,062)
Decrease in liabilities due to disposition	-	(654)
Accretion of liability	4,439	3,504
Carrying amount, end of year	\$ 59,432	\$ 43,886

Provident funds a cash reserve for future site reclamation by paying \$0.30 per barrel of oil equivalent produced on a 6:1 basis into a segregated cash account. Actual expenditures are then funded from the cash in this account. The cash account has been depleted since 2006 as actual expenditures have exceeded contributions to the reserve.

10. Unitholders' contributions

The Trust has authorized capital of an unlimited number of common voting trust units.

Trust units are redeemable at any time on demand by the holders thereof. Upon receipt of a redemption request by the Trust, the holder is entitled to receive a price per trust unit (the "Market Redemption Price") equal to the lesser of: (i) 90 percent of the simple average of the closing price of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are surrendered for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are surrendered for redemption.

The aggregate Market Redemption Price payable by the Trust in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. Total cash payments for redemption are limited to an annual maximum of \$250,000. Any excess over the maximum may be satisfied by distributing notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the trust units tendered for redemption.

i) 2008 activity

In 2008, the Trust issued 6.5 million units related to Provident's DRIP program, conversion of convertible debentures to units and units issued pursuant to Provident's Unit Option Plan. The increase in unitholders' contributions associated with these activities was \$55.7 million.

ii) 2007 activity

In 2007, the Trust issued 29,313,727 trust units at a price of \$12.75 per unit for total proceeds of \$373.8 million (\$354.6 million net of issue costs). Proceeds from the issue were used to fund the Capitol acquisition, which closed on June 19, 2007.

On December 3, 2007 the Trust issued 6.3 million units (at an ascribed value of \$76.6 million) as part of the consideration to acquire the outstanding shares of Triwest Energy Inc.

In 2007, the Trust issued 5.8 million units related to Provident's DRIP program, conversion of convertible debentures to units and units issued pursuant to Provident's Unit Option Plan. The increase in unitholders' contributions associated with these activities was \$65.2 million.

Trust Units	Year ended December 31,			
	2008		2007	
	Number of units	Amount (000s)	Number of units	Amount (000s)
Balance at beginning of year	252,634,773	\$ 2,750,374	211,228,407	\$ 2,254,048
Issued for cash	-	-	29,313,727	373,750
Issued to acquire Triwest Energy inc.	-	-	6,251,149	76,577
Issued pursuant to unit option plan	191,448	1,790	825,349	8,426
Issued pursuant to the distribution reinvestment plan	5,600,810	50,667	3,941,864	45,338
To be issued pursuant to the distribution reinvestment plan	655,142	3,171	525,822	5,153
Debenture conversions	5,616	69	548,455	6,270
Unit issue costs	-	-	-	(19,188)
Balance at end of year	259,087,789	\$ 2,806,071	252,634,773	\$ 2,750,374

The basic per trust unit amounts for 2008 were calculated based on the weighted average number of units outstanding of 255,177,346 (2007 – 229,939,158). The diluted per trust unit amounts for 2008 are calculated including no additional trust units (2007 – nil) for the dilutive effect of the unit option plan and the convertible debentures.

11. Unit based compensation**i) Restricted/Performance units**

Certain employees of the Trust are granted restricted trust units (RTUs) and/or performance trust units (PTUs), both of which entitle the employee to receive cash compensation in relation to the value of a specific number of underlying notional trust units. The grants are based on criteria designed to recognize the long term value of the employee to the organization. RTUs vest evenly over a period of three years commencing at the grant date. Payments are made on the anniversary dates of the RTU to the employees entitled to receive them on the basis of a cash payment equal to the value of the underlying notional units. PTUs vest three years from the date of grant and can be increased to a maximum of double the PTUs granted or a minimum of nil PTUs depending on the Trust's performance vis-à-vis other trusts' performance based on certain benchmarks.

As of December 31, 2008 there were 1,139,835 RTUs and 3,400,330 PTUs outstanding (2007 – 849,672 RTUs and 2,478,037 PTUs). The fair value estimate associated with the RTUs and PTUs is expensed in the statement of operations over the vesting period. At December 31, 2008, \$9.4 million (2007 - \$9.9 million) is included in accounts payable and accrued liabilities for this plan and \$8.6 million (2007 - \$12.4 million) is included in other long-term liabilities. The following table reconciles the expense recorded for RTUs and PTUs.

		Year ended December 31,	
		2008	2007
Cash general and administrative	\$	8,287	\$ 1,767
Non-cash unit based compensation (included in general and administrative)		(4,117)	8,007
Production, operating and maintenance expense		266	430
	\$	4,436	\$ 10,204

ii) Unit option plan

The Trust option plan (the "Plan") is administered by the Board of Directors of Provident. In October 2005, a restricted/performance unit program (see (i)) was approved. This program replaced the unit option plan. Unit options in existence continue to be outstanding until exercised or expired.

At December 31, 2008, the Trust had 967,026 options outstanding and exercisable (2007 – 1,279,169) with strike prices ranging between \$10.92 and \$12.14 per unit (2007 – between \$10.49 and \$12.14). The weighted average exercise price was \$11.08 per unit (2007 - \$11.04) excluding average potential reductions to the strike prices of \$2.14 per unit (2007 - \$1.77).

The following table reconciles the movement in the contributed surplus balance.

		Year ended December 31,	
		2008	2007
Contributed surplus, beginning of the year	\$	801	\$ 1,315
Non-cash unit based compensation (included in general and administrative)		-	57
Benefit on options exercised charged to unitholders' contributions		(117)	(571)
Transferred from convertible debentures equity component on maturity (see note 8)		1,011	-
Contributed surplus, end of year	\$	1,695	\$ 801

12. Income taxes

In 2007, future income tax expense includes \$88.4 million relating to the enactment of Bill C-52, Budget Implementation Act 2007 by the Canadian government. This bill contains legislation to tax publicly traded trusts including the Trust. As a result of this legislation, the Trust is required to record the future tax effect of the temporary differences on its flow through entities that are expected to reverse subsequent to 2010.

Although the Trust believes it will be subject to additional tax under the legislation, the estimated effective tax rate on temporary difference reversals after 2011 may change in future periods. Future technical interpretations of the legislation could occur and could materially affect management's estimate of the future income tax liability.

The amount and timing of reversals of temporary differences will also depend on the Trust's future operating results, acquisitions and dispositions of assets and liabilities, and distribution policy. A significant change in any of the preceding assumptions could materially affect the Trust's estimate of the future tax liability.

The future income tax liability is comprised of the following:

	Year ended December 31,	
	2008	2007
Property, plant and equipment in excess of tax value	\$ 378,663	\$ 416,319
Asset retirement obligation	(16,863)	(13,360)
Financial derivative instruments	(15,123)	(52,050)
Non-capital losses	(68,414)	(47,318)
Other	(10,456)	(1,502)
	\$ 267,807	\$ 302,089

The income tax provision differs from the expected amount calculated by applying the Trust's combined federal and provincial/state income tax rate of 30.96 percent (2007 – 32.81 percent) as follows:

	Year ended December 31,	
	2008	2007
Expected income tax recovery, from continuing operations	\$ (6,135)	\$ (44,030)
Increase (decrease) resulting from:		
Future income tax expense relating to enactment of Bill C-52, Budget Implementation Act 2007	-	88,352
Goodwill impairment (permanent difference)	124,992	-
Income of the Trust and other	(142,169)	(64,558)
Capital taxes	3,109	3,762
Withholding tax and other	(498)	3,425
Income tax rate differences	(10,484)	(5,193)
Income tax recovery, from continuing operations	\$ (31,185)	\$ (18,242)

13. Financial instruments

Risk Management Overview

Provident has a comprehensive Enterprise Risk Management program that is designed to identify and manage risks that could negatively affect its business, operations or results. The program's activities include risk identification, assessment, response, control, monitoring and communication.

Provident's Risk Management group executes the program with oversight from the Risk Management Committee ("RMC"), which provides regular reports to the Audit Committee and Board of Directors.

Provident has established and implemented Risk Management strategies, policies and limits that are monitored by Provident's Risk Management group. The derivative instruments the Trust uses include put and call options, costless collars, participating swaps, and fixed price products that settle against indexed referenced pricing. Put option contracts effectively create a floor price for the commodity while allowing for full participation if prices increase. Call options are contracts that allow for a commodity to be sold at a fixed price at the option of the contract holder. Costless collars are contracts that provide a floor and a ceiling price to limit the risk if prices fall and allowing upward participation within a set range. Participating swaps are contracts that provide a floor and also provide a ceiling for a certain percentage of the volume of the contract. This type of derivative allows for price protection if the price falls, while still allowing some participation if the price increases. Fixed price swaps are contracts that specify a fixed price at which a certain volume of product will be bought or sold at in the future.

The Risk Management group monitors risk exposure by generating and reviewing mark-to-market reports and counterparty credit exposure of Provident's outstanding derivative contracts. Additional monitoring activities include reviewing available derivative positions, regulatory changes and bank and analyst reports.

Provident's commodity price risk management program utilizes derivative instruments to provide for insurance against lower commodity prices and product margins, as well as fluctuating interest and foreign exchange rates. The program is designed to stabilize cash flows in order to support cash distributions, capital programs and bank financing. The risk management strategy protects a percentage of Provident's oil and natural gas production against a decline in commodity prices. Provident seeks to use products that allow participation in a rising commodity price environment where possible and economic. The program provides price stabilization and protection of a percentage of inventory values and fractionation spread margin associated with the midstream business unit. As well, the Provident risk management strategy reduces foreign exchange risk due to the exposure arising from the conversion of U.S. dollars into Canadian dollars.

Fair Values

The fair values of financial instruments are determined by reference to independent monthly forward settlement prices, interest rate yield curves, currency rates, and volatility rates at the period-end dates. All of Provident's financial instruments are executed in liquid markets.

Management believes that financial markets currently provide adequate liquidity through price discovery and active credit-worthy counterparties for Provident to continue to execute the program in 2009.

As at December 31,, 2008	Held for Trading	Available for Sale	Loans and Receivables	Other Liabilities	Total Carrying Value
Assets					
Accounts receivable	\$ -	\$ -	\$ 244,485	\$ -	\$ 244,485
Financial derivative instruments					
- current assets	16,708	-	-	-	16,708
- long term assets	735	-	-	-	735
Investments and other long-term assets	-	1,972	12,246	-	14,218
	\$ 17,443	\$ 1,972	\$ 256,731	\$ -	\$ 276,146
Liabilities					
Accounts payable and accrued liabilities	\$ -	\$ -	\$ -	\$ 244,031	\$ 244,031
Cash distributions payable	-	-	-	20,088	20,088
Current portion of convertible debentures	-	-	-	24,871	24,871
Financial derivative instruments					
- current liabilities	13,693	-	-	-	13,693
Long-term debt - revolving term credit facilities	-	-	-	504,685	504,685
Long-term debt - convertible debentures	-	-	-	236,123	236,123
Financial derivative instruments					
- long -term liabilities	58,420	-	-	-	58,420
Other long-term liabilities	-	-	-	8,572	8,572
	\$ 72,113	\$ -	\$ -	\$ 1,038,370	\$ 1,110,483

Except as disclosed in note 8 in connection with the convertible debentures, there were no significant differences between the carrying value of these financial instruments and their estimated fair value as at December 31, 2008.

The following table is a summary of the net financial derivative instruments liability:

	As at December 31, 2008	As at December 31, 2007
(\$000s)		
Provident Upstream		
Crude Oil	\$ (12,521)	\$ 19,215
Natural Gas	(3,285)	(5,901)
Provident Midstream	70,476	261,587
Corporate	-	245
Total	\$ 54,670	\$ 275,146

Market Risk

Market risk is the risk that the fair value of a financial instrument will fluctuate because of changes in market prices. Market risk generally comprises of price risk, currency risk and interest rate risk.

a) Price risk

Commodity Price Risk Management Program

The decisions to enter into financial derivative positions and to execute the risk management strategy are made by senior officers of Provident who are also members of the RMC. The RMC receives input and commodity expertise from each business unit in the decision making process. Strategies are selected based on their ability to help Provident provide stable cash flow and distributions per unit rather than to simply lock in a specific price per barrel of oil or cubic foot of natural gas.

Oil and Natural Gas

Provident's risk management program employs derivative instruments, such as puts, participating swaps, costless collars and fixed price swaps, to protect a floor level of Provident's revenue on a portion of the oil and gas sold. At the same time, these instruments may enable Provident to retain various levels of participation to the extent oil and gas prices rise. Provident may also use derivative instruments for its oil and natural gas business line to protect acquisition economics.

The major identified risks for the oil and natural gas business line are commodity price volatility and market location and product quality differentials. Provident addresses these risks using a risk management program designed to protect a portion of its cash flow in order to support continued unitholder distributions, capital programs and bank financing.

Midstream

Commodity price volatility and market location differentials also affect the Midstream business. In addition, Midstream is exposed to possible price declines between the time Provident purchases natural gas liquid (NGL) feedstock and sells NGL products, and to narrowing frac spread ratios. Frac spread ratio is the ratio between crude oil prices and natural gas prices. There is also a differential between NGL product prices (propane, butane and condensate) and crude oil prices.

Provident responds to these risks using a risk management program that protects a margin or floor level of operating income on a portion of its NGL inventory and production, while retaining some ability to participate in a widening margin environment. For the longer-term, Provident uses crude oil contracts in place of NGLs. Provident may replace these contracts with NGL product contracts as market conditions allow. This strategy enables Provident to mitigate commodity price risk related to its NGL production business up to approximately five years into the future.

b) Currency risk

Provident's oil, natural gas and NGL sales are exposed to both positive and negative effects of fluctuations in the Canadian/U.S. exchange rate. Provident manages this exposure by matching a significant portion of the cash costs that it expects with revenues in the same currency. As well, Provident uses derivative instruments to manage the U.S. cash requirements of its business lines.

Provident regularly sells or purchases forward a portion of expected U.S. cashflows. Provident's strategy also manages the exposure it has to fluctuations in the U.S./Canadian dollar exchange rate when the underlying commodity price is based upon a U.S. index price. Provident may also use derivative products that provide for protection against a stronger Canadian dollar, while allowing it to participate if the currency weakens relative to the U.S. dollar.

c) Interest rate risk

The Trust's revolving term credit facilities bear interest at a floating rate. Using debt levels as at December 31, 2008, an increase/decrease of 50 basis points in the lender's base rate would result in an increase/decrease of annual interest expense of approximately \$2.5 million.

Financial derivative sensitivity analysis

The following table shows the impact on unrealized gain (loss) on financial derivative instruments if the underlying risk variables of the financial derivative instruments changed by a specified amount, with other variables held constant.

Cdn (000's)		+ Change	- Change
Provident Upstream			
Crude Oil	(WTI +/- \$10.00 per bbl)	\$ (6,222)	\$ 6,836
Natural Gas	(AECO +/- \$1.00 per gj)	(1,776)	1,951
Provident Midstream			
Frac spread related			
Crude Oil	(WTI +/- \$10.00 per bbl)	(109,232)	109,841
Natural Gas	(AECO +/- \$1.00 per gj)	67,264	(67,075)
NGL's (includes propane, butane, natural gasoline)	(Belvieu +/- US \$0.15 per gal)	(413)	413
Foreign Exchange (\$U.S. vs \$Cdn)	(FX rate +/- \$ 0.01)	(2,299)	2,283
Inventory/margin related			
Crude Oil	(WTI +/- \$10.00 per bbl)	(13,872)	13,885
Natural Gas	(AECO +/- \$1.00 per gj)	(78)	78
NGL's (includes propane, butane, natural gasoline)	(Belvieu +/- US \$0.15 per gal)	11,645	(11,625)

Liquidity Risk

Liquidity risk is the risk the Trust will not be able to meet its financial obligations as they come due. The Trust's approach to managing liquidity risk is to ensure that it always has sufficient cash and credit facilities to meet its obligations when due, without incurring unacceptable losses or damage to the Trust's reputation.

Management typically forecasts cash flows for a period of twelve months to identify financing requirements. These requirements are then addressed through a combination of committed and demand credit facilities and access to capital markets, as discussed in note 14.

The following table outlines the timing of the cash outflows relating to financial liabilities.

As at December 31, 2008		Payment due by period			
(\$000s)	Total	Less than			
		1 year	1 to 3 years	4 to 5 years	
Accounts payable and accrued liabilities	\$ 244,031	\$ 244,031	\$ -	\$ -	
Cash distributions payable	20,088	20,088	-	-	
Current portion of convertible debentures ⁽²⁾	26,281	26,281	-	-	
Financial derivative instruments - current	13,693	13,693	-	-	
Long-term debt - revolving term credit facilities ⁽¹⁾⁽²⁾	548,761	16,784	531,977	-	
Long-term debt - convertible debentures ⁽²⁾	295,322	16,184	175,849	103,289	
Long-term financial derivative instruments	58,420	-	43,147	15,273	
Other long-term liabilities	8,572	-	8,572	-	
Total	\$ 1,215,168	\$ 337,061	\$ 759,545	\$ 118,562	

⁽¹⁾ The terms of the Canadian credit facility have a revolving three year period expiring on May 30, 2011.

⁽²⁾ Includes associated interest and principal payments.

Credit Risk

Provident's Credit Policy governs the activities undertaken to mitigate the risks associated with counterparty (customer) non-payment. The Policy requires a formal credit review for counterparties entering into a commodity contract with Provident. This review determines an approved credit limit. Activities undertaken include regular monitoring of counterparty exposures to approved credit limits, financial review of all active counterparties, utilizing master netting arrangements and International Swap Dealers Association (ISDA) agreements and obtaining financial assurances where warranted. Financial assurances include guarantees, letters of credit and cash. In addition, Provident has a diversified base of creditors.

Substantially all of the Trust's accounts receivable are due from customers and joint venture partners in the oil and gas and midstream services and marketing industries and are subject to credit risk. The Trust partially mitigates associated credit risk by limiting transactions with certain counterparties to limits imposed by the Trust based on management's assessment of the creditworthiness of such counterparties. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

Financial Derivative Instruments – 2008 Activity

i) Provident Upstream

a) Crude oil

In 2008, Provident paid \$11.1 million (2007 - \$7.9 million) to settle various oil market based contracts on an aggregate volume of 1.6 million barrels (2007 – 1.6 million barrels). The estimated value of contracts in place if settled at market prices at December 31, 2008 would have resulted in an opportunity gain of \$12.5 million (2007 – \$19.2 million opportunity cost).

b) Natural Gas

In 2008, Provident received nil (2007 - \$9.6 million) to settle various natural gas market based contracts on an aggregate of 10.9 million gigajoules (“gj”) (2007 – 16.7 million gj's). The estimated value of contracts in place if settled at market prices at December 31, 2008 would have resulted in an opportunity gain of \$3.3 million (2007 – \$5.8 million).

ii) Provident Midstream

In 2008, Provident paid \$135.6 million (2007 – received \$17.9 million) to settle Midstream oil market based contracts on an aggregate volume of 4.2 million barrels (2007 - 1.2 million barrels) and paid \$17.0 million (2007 - \$48.7 million) to settle Midstream natural gas market based contracts on an aggregate volume of 26.8 million gj's (2007 – 25.3 million gj's). In addition, Provident received \$25.9 million (2007 – paid \$48.2 million) to settle Midstream NGL market based contracts on an aggregate volume of 2.3 million barrels (2007 – 7.2 million barrels).

Provident also received \$5.4 million (2007 - \$4.6 million) to settle Midstream-related foreign exchange contracts, and received \$2.4 million (2007 – nil) to settle various electricity-based contracts. The estimated value of contracts in place if settled at market prices at December 31, 2008 would have resulted in an opportunity cost of \$70.5 million (2007 – \$261.6 million).

iii) Corporate

a) Foreign exchange contracts

In 2008, Provident received \$26.8 million to settle various corporate-related foreign exchange contracts (2007 - \$1.3 million). Realized gains and losses on corporate-related foreign exchange contracts are included in foreign exchange (gain) loss and other on the consolidated statement of operations and are allocated to the reporting segments for segmented reporting purposes. The estimated value of contracts in place if settled at foreign exchange rates at December 31, 2008 would have resulted in an opportunity cost of nil (2007 – \$0.1 million).

The contracts in place at December 31, 2008 are summarized in the following tables:

Provident Upstream

Year	Product	Volume (Buy)/Sell	Terms	Effective Period
2009	Crude Oil	2,000 Bpd	WCS Blend at 80% of US\$ WTI	January 1 - March 31
		2,283 Bpd	Participating Swap US \$62.36 per bbl (Participation Range 52% to 90% above the floor price)	January 1 - December 31
	Natural Gas	5,000 Gjpd	Puts Cdn \$9.29 per gj	January 1 - March 31
		4,871 Gjpd	Participating Swap Cdn \$6.93 per gj (Participation Range 20% to 95% above the floor price)	January 1 - December 31

Provident Midstream

Year	Product	Volume (Buy)/Sell	Terms	Effective Period
2009	Crude Oil	7,038 Bpd	Cdn \$74.20 per bbl	January 1 - December 31
		750 Bpd	US \$65.97 per bbl	January 1 - December 31
		2,973 Bpd	US \$85.16 per bbl ⁽¹²⁾	January 1 - December 31
		(1,052) Bpd	Cdn \$70.21 per bbl ⁽¹⁰⁾	January 1 - November 30
		(420) Bpd	US \$88.30 per bbl ⁽⁹⁾	January 1 - March 31
		323 Bpd	US \$57.78 per bbl ⁽¹¹⁾	May 1 - May 31
		2,748 Bpd	Costless Collar US \$65.27 floor, US \$70.23 ceiling	January 1 - December 31
	Natural Gas	621 Bpd	Participating Swap Cdn \$78.27 per bbl (Average Participation 38% above the floor price)	September 1 - December 31
		1,052 Bpd	Participating Swap US \$71.31 per bbl (Average Participation 54% above the floor price)	July 1 - November 30
		(60,255) Gjpd	Cdn \$8.15 per gj	January 1 - December 31
		2,500 Gjpd	Cdn \$6.56 per gj ⁽¹¹⁾	January 1 - January 31
		(3,477) Gjpd	Participating Swap Cdn \$7.86 per gj (Average Participation 33% below the ceiling price)	July 1 - December 31
		(2,810) Gjpd	Costless Collar Cdn \$6.20 floor, Cdn \$7.10 ceiling	September 1 - October 31
	Propane	760 Bpd	US \$1.32 per gallon ⁽⁵⁾⁽¹¹⁾	January 1 - March 31
		600 Bpd	US \$1.265 per gallon ⁽⁹⁾	January 1 - March 31
		333 Bpd	US \$0.99 per gallon ⁽⁶⁾⁽¹¹⁾	January 1 - March 31
	Natural Gasoline	(2,973) Bpd	US \$1.74 per gallon ⁽¹²⁾	January 1 - December 31
	Normal Butane	(1,473) Bpd	US \$0.76 per gallon ⁽¹²⁾	April 1 - December 31
	Foreign Exchange		Sell US \$6,432,441 per month @ 1.1117 ⁽¹³⁾	January 1 - December 31
			Sell US \$1,055,833 per month @ 1.099 ⁽¹³⁾	January 1 - June 30
			Sell US \$1,972,561 per month @ 1.0244 ⁽¹³⁾	July 1 - August 31
			Sell US \$596,166 per month @ 0.9815 ⁽¹³⁾	July 1 - October 31
			Sell US \$1,686,650 per month @ 0.9622 ⁽¹³⁾	September 1 - October 31
			Sell US \$1,809,600 per month @ 1.0098 ⁽¹³⁾	November 1 - November 30

Provident Midstream cont'd.

Year	Product	Volume (Buy)/Sell	Terms	Effective Period
2010	Crude Oil	6,238 Bpd	Cdn \$73.19 per bbl	January 1 - December 31
		500 Bpd	US \$66.65 per bbl	January 1 - December 31
		1,750 Bpd	Costless Collar US \$61.63 floor, US \$66.56 ceiling	January 1 - December 31
		464 Bpd	Participating Swap Cdn \$77.01 per bbl (Average Participation 37% above the floor price)	January 1 - December 31
	Natural Gas	860 Bpd	Participating Swap US \$74.89 per bbl (Average Participation 48% above the floor price)	January 1 - December 31
		(47,181) Gjpd	Cdn \$7.83 per gj	January 1 - December 31
	Normal Butane	(5,756) Gjpd	Participating Swap Cdn \$7.77 per gj (Average Participation 28% below the ceiling price)	January 1 - December 31
		(1,500) Bpd	US \$0.76 per gallon ⁽¹²⁾	January 1 - March 31
	Foreign Exchange		Sell US \$4,773,059 per month @ 1.1110 ⁽¹³⁾	January 1 - December 31
			Sell US \$582,821 per month @ 1.0159 ⁽¹³⁾	January 1 - August 31
			Sell US \$1,420,921 per month @ 0.9781 ⁽¹³⁾	July 1 - August 31
			Sell US \$587,903 per month @ 1.0165 ⁽¹³⁾	July 1 - November 30
			Sell US \$2,254,103 per month @ 0.9578 ⁽¹³⁾	September 1 - October 31
			Sell US \$2,394,058 per month @ 1.0154 ⁽¹³⁾	September 1 - November 30
			Sell US \$629,673 per month @ 1.0165 ⁽¹³⁾	November 1 - December 31
2011	Crude Oil	5,534 Bpd	Cdn \$71.73 per bbl	January 1 - December 31
		1,005 Bpd	Costless Collar US \$60.64 floor, US \$73.45 ceiling	January 1 - September 30
		416 Bpd	Participating Swap Cdn \$84.38 per bbl (Average Participation 25% above the floor price)	October 1 - December 31
		250 Bpd	Participating Swap US \$63.00 per bbl (Average Participation 64% above the floor price)	January 1 - December 31
	Natural Gas	(37,595) Gjpd	Cdn \$7.32 per gj	January 1 - December 31
		(2,337) Gjpd	Participating Swap Cdn \$8.28 per gj (Average Participation 25% below the ceiling price)	October 1 - December 31
	Foreign Exchange		Sell US \$479,063 per month @ 0.9725 ⁽¹³⁾	January 1 - December 31
			Sell US \$980,417 per month @ 1.0805 ⁽¹³⁾	January 1 - June 30
			Sell US \$3,588,000 per month @ 1.0918 ⁽¹³⁾	July 1 - September 30
2012	Crude Oil	3,637 Bpd	Cdn \$72.57 per bbl	January 1 - December 31
		1,445 Bpd	Participating Swap Cdn \$85.19 per bbl (Average Participation 27% above the floor price)	February 1 - December 31
		1,352 Bpd	Participating Swap US \$72.22 per bbl (Average Participation 51% above the floor price)	March 1 - December 31
	Natural Gas	(25,717) Gjpd	Cdn \$7.24 per gj	January 1 - December 31
		(9,318) Gjpd	Participating Swap Cdn \$8.55 per gj (Average Participation 28% below the ceiling price)	February 1 - December 31
	Foreign Exchange		Sell US \$2,016,783 per month @ 1.0119 ⁽¹³⁾	March 1 - March 31
			Sell US \$1,041,721 per month @ 0.9413 ⁽¹³⁾	April 1 - October 31
			Sell US \$681,260 per month @ 0.9850 ⁽¹³⁾	May 1 - October 31
			Sell US \$1,437,986 per month @ 0.9659 ⁽¹³⁾	July 1 - December 31
			Sell US \$1,634,227 per month @ 0.9829 ⁽¹³⁾	October 1 - December 31
			Sell US \$1,420,538 per month @ 0.9995 ⁽¹³⁾	November 1 - December 31
2013	Crude Oil	250 Bpd	Cdn \$75.32 per bbl	January 1 - January 31
		1,250 Bpd	Participating Swap Cdn \$84.90 per bbl (Average Participation 25% above the floor price)	January 1 - March 31
		758 Bpd	Participating Swap US \$85.62 per bbl (Average Participation 30% above the floor price)	January 1 - March 31
	Natural Gas	(7,025) Gjpd	Cdn \$7.19 per gj	January 1 - January 31
		(9,524) Gjpd	Participating Swap Cdn \$8.87 per gj (Average Participation 22% below the ceiling price)	January 1 - March 31
	Foreign Exchange		Sell US \$1,651,990 per month @ 0.9829 ⁽¹³⁾	January 1 - January 31
			Sell US \$1,397,250 per month @ 0.9995 ⁽¹³⁾	January 1 - March 31

⁽¹⁾ The above table represents a number of transactions entered into over an extended period of time.

⁽²⁾ Natural gas contracts are settled against AECO monthly index.

⁽³⁾ Crude Oil contracts are settled against NYMEX WTI calendar average.

⁽⁴⁾ WCS contracts are settled against NYMEX WTI calendar average plus the monthly index for physical WCS (quoted as a differential to WTI) by NetThruPut Inc.

⁽⁵⁾ Propane contracts are settled against Belvieu C3 TET.

⁽⁶⁾ Propane contracts are settled against Conway In-Well C3.

⁽⁷⁾ Normal Butane contracts are settled against Belvieu NC4 TET.

⁽⁸⁾ Natural Gasoline contracts are settled against Belvieu NON-TET Natural Gasoline.

⁽⁹⁾ Conversion of Crude Oil BTU contracts to liquids.

⁽¹⁰⁾ BTU re-balancing of Crude Oil contracts.

⁽¹¹⁾ Midstream inventory price stabilization contracts.

⁽¹²⁾ Midstream margin contracts.

⁽¹³⁾ US Dollar forward contracts are settled against the Bank of Canada noon rate average.

14. Capital management

Provident considers its total capital to be comprised of net debt and Unitholders' Equity. Net debt is comprised of long-term debt and working capital surplus, excluding balances for the current portion of financial derivative instruments. The balance of these items at December 31, 2008 and December 31, 2007 was as follows:

	As at December 31, 2008	As at December 31, 2007
(\$000s)		
Working capital surplus ⁽¹⁾	\$ (39,041)	\$ (58,732)
Long-term debt (including current portion)	765,679	1,199,634
Net debt	726,638	1,140,902
Unitholders' equity	1,636,347	1,708,665
Total capitalization	\$ 2,362,985	\$ 2,849,567
Net debt to total capitalization	31%	40%

⁽¹⁾ The working capital surplus excludes balances for the current portion of financial derivative instruments.

Provident's primary objective for managing capital is to maximize long-term Unitholder value by:

- providing an appropriate return to shareholders relative to the risk of Provident's underlying assets; and
- ensuring financing capacity for Provident's internal development opportunities and acquisitions of energy related assets that are expected to add value to our Unitholders.

Provident makes adjustments to its capital structure based on economic conditions and the Trust's planned requirements. Provident has the ability to adjust its capital structure by issuing new equity or debt, controlling the amount it returns to unitholders, and making adjustments to its capital expenditure program. Provident relies on cash flow from operations, external lines of credit and access to equity markets to fund capital programs and acquisitions.

The Trust is subject to certain capital growth restrictions as a result of the Canadian trust tax legislation passed in June 2007 and effective January 1, 2011. The restrictions provide that "normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006. These rules limit the amount of Unitholders' capital that can be issued by the Trust in each of the next two years, as follows:

(\$ billions)	Annual	Cumulative
Normal growth capital allowed in:		
2009 ⁽¹⁾	0.6	2.3
2010	0.5	2.8

⁽¹⁾ The Trust's allowed growth capital prior to 2009 was approximately \$1.7 billion.

If the maximum equity growth allowed is exceeded, the Trust may be subject to trust taxation prior to 2011. In 2007 and 2008, the Trust issued equity amounting to \$552.0 million.

15. Discontinued operations (USOGP)

In February 2008, the Trust announced a strategic process respecting the decision to dispose of the operations that comprise the United States oil and natural gas production (USOGP) business. Effective in the first quarter of 2008, Provident's USOGP business is accounted for as discontinued operations and comparative figures have been reclassified to conform with this presentation.

In June 2008, the Trust sold a portion of the USOGP business, consisting of its 22 percent interest in BreitBurn Energy Partners, L.P. (MLP) and its 96 percent interest in BreitBurn GP LLC, for cash proceeds, net of

transaction costs, of U.S. \$342.2 million. The Trust has recorded a gain on sale of \$187.9 million and \$127.7 million in current tax expense related to this transaction. Also recorded was a realized foreign exchange loss of \$30.3 million, representing the recognition of the related portion of the foreign exchange loss in accumulated other comprehensive income, which was generated since inception in 2006. These amounts are recorded as part of net income from discontinued operations for the year ended December 31, 2008.

In August 2008, the Trust sold the remaining portion of the USOGP business, comprised of an approximate 96 percent interest in BreitBurn Energy Company L.P., for total consideration of U.S. \$300.4 million, consisting of cash proceeds, net of transaction costs, of U.S. \$290.4 million and a U.S. \$10 million note. The Trust has recorded a gain on sale of \$75.7 million and \$66.9 million in current tax expense related to this transaction. Also recorded was a realized foreign exchange loss of \$26.8 million, representing the recognition of the related portion of the foreign exchange loss in accumulated other comprehensive income, which was generated since acquisition in 2004. These amounts are recorded as part of net income from discontinued operations for the year ended December 31, 2008.

During 2008, the Trust made tax installment payments for the amounts relating to the sales of the MLP, BreitBurn GP LLC and BreitBurn Energy Company L.P.

Quicksilver Resources Inc. ("Quicksilver") filed a lawsuit on October 31, 2008 against the MLP, certain of its directors (including three Provident nominees), and Provident. The claim relates to a transaction between the MLP and Quicksilver and certain other MLP matters. Quicksilver alleges, among other things, that it was induced to enter into a contribution agreement pursuant to which it contributed assets to the MLP by false representations as to Provident's relationship with the MLP. The transaction involved the issuance by the MLP to Quicksilver of approximately U.S.\$700 million of units of the MLP. The litigation is in its very early stages, and it is not possible at this time to assess the potential exposure of Provident in the event of an adverse verdict. Provident believes the claims made against it in the lawsuit are without merit and will vigorously defend itself and its named director nominees against these claims.

The following tables show the net assets of discontinued operations and information about net income from USOGP.

	As at December 31, 2008	As at December 31, 2007
Balance sheets		
Canadian dollars (000s)		
Assets		
Current assets	\$ -	\$ 93,578
Property, plant and equipment	-	2,008,549
Other long-term assets	-	19,055
	-	2,027,604
	\$ -	\$ 2,121,182
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	\$ -	\$ 77,244
Financial derivative instruments	-	37,437
	-	114,681
Long-term debt - revolving term credit facilities	-	368,836
Long-term financial derivative instruments	-	66,382
Asset retirement obligation and other long-term liabilities	-	45,373
Future income taxes	-	147,911
	-	628,502
Non-controlling interests	-	1,100,136
Net Assets - discontinued operations	\$ -	\$ 277,863

Net income from discontinued operations Canadian dollars (000's)	Year ended December 31,	
	2008	2007
Revenue	\$ 303,146	\$ 246,760
Loss from discontinued operations before taxes, non-controlling interests, dilution gain and impact of sale of discontinued operations	(237,233)	(90,748)
Dilution gain	-	260,324
Gain on sale of discontinued operations	263,618	-
Foreign exchange loss related to sale of discontinued operations	(57,062)	-
Current and withholding tax expense	(178,708)	(10)
Future income tax recovery (expense)	151,975	(58,843)
Non-controlling interests	203,434	35,666
Net income from discontinued operations	\$ 146,024	\$ 146,389

16. Commitments

Provident has office lease commitments that extend through June 2022. Future minimum lease payments for the following five years are: 2009 - \$8.7 million; 2010 - \$8.5 million; 2011 - \$8.5 million; 2012 - \$8.8 million, and 2013 - \$9.0 million.

In relation to the midstream services and marketing segment, Provident is committed to minimum lease payments under the terms of various rail tank car leases for the following five years: 2009 – \$9.3 million; 2010 – \$7.0 million; 2011 – \$5.6 million; 2012 – \$3.1 million and 2013 - \$0.8 million. Additionally, under an arrangement to use a third party interest in the Younger plant, Provident has a commitment to make payments calculated with reference to a number of variables including return on capital. Payments for the next five years are estimated as follows: 2009 - \$4.3 million; 2010 - \$4.1 million; 2011 – \$3.9 million; 2012 - \$3.8 million and 2013 - \$3.6 million.

17. Segmented information

The Trust's business activities are conducted through two business segments: Canadian oil and natural gas production ("COGP" or "Provident Upstream") and Provident Midstream.

Provident Upstream includes exploitation, development and production of crude oil and natural gas reserves. Provident Midstream includes processing, extraction, transportation, loading and storage of natural gas liquids, and marketing of natural gas liquids.

Geographically the Trust operates in Canada in the oil and gas production business segment and in Canada and the USA in the Midstream business.

	Year ended December 31, 2008		
	Provident Upstream	Provident Midstream ⁽¹⁾	Total
Revenue			
Gross production revenue	\$ 681,336	\$ -	\$ 681,336
Royalties	(123,140)	-	(123,140)
Product sales and service revenue	-	2,589,518	2,589,518
Realized loss on financial derivative instruments	(11,102)	(118,917)	(130,019)
	547,094	2,470,601	3,017,695
Expenses			
Cost of goods sold	-	2,206,427	2,206,427
Production, operating and maintenance	138,173	14,938	153,111
Transportation	16,320	20,800	37,120
Foreign exchange (gain) loss and other	2,917	(19,853)	(16,936)
General and administrative	36,191	35,528	71,719
	193,601	2,257,840	2,451,441
Earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items	353,493	212,761	566,254
Other revenue			
Unrealized gain (loss) on financial derivative instruments	30,230	191,238	221,468
Other expenses			
Depletion, depreciation and accretion	304,909	38,406	343,315
Goodwill impairment	416,890	-	416,890
Interest on bank debt	9,022	27,066	36,088
Interest and accretion on convertible debentures	4,986	14,958	19,944
Unrealized foreign exchange (gain) loss and other	4,296	(8,188)	(3,892)
Non-cash unit based compensation	(2,199)	(1,918)	(4,117)
Internal management charge	(689)	-	(689)
Capital tax expense	3,109	-	3,109
Current and withholding tax (recovery) expense	(212)	(4,317)	(4,529)
Future income tax (recovery) expense	(50,339)	20,574	(29,765)
	689,773	86,581	776,354
Net income (loss) for the year from continuing operations	\$ (306,050)	\$ 317,418	\$ 11,368
Net income from discontinued operations (note 15)			146,024
Net income for the year			\$ 157,392

⁽¹⁾ Included in the Provident Midstream segment is product sales and service revenue of \$307.9 million associated with U.S. operations.

	As at and for the year ended December 31, 2008		
	Provident Upstream	Provident Midstream	Total
Selected balance sheet items			
Capital assets			
Property, plant and equipment net	\$ 1,731,331	\$ 749,172	\$ 2,480,503
Intangible assets	-	158,336	158,336
Goodwill	-	100,409	100,409
Capital expenditures			
Capital Expenditures	209,147	37,800	246,947
Oil and gas property acquisitions, net	24,181	-	24,181
Goodwill additions (impairments)	(416,890)	-	(416,890)
Working capital			
Accounts receivable	60,839	183,646	244,485
Petroleum product inventory	-	46,160	46,160
Accounts payable and accrued liabilities	114,152	129,879	244,031
Long-term debt - revolving term credit facilities	126,171	378,514	504,685
Long-term debt - convertible debentures	59,031	177,092	236,123
Financial derivative instruments (asset) liability	\$ (15,806)	\$ 70,476	\$ 54,670

Year ended December 31, 2007

	Provident Upstream	Provident Midstream ⁽¹⁾	Total
Revenue			
Gross production revenue	\$ 454,179	\$ -	\$ 454,179
Royalties	(87,046)	-	(87,046)
Product sales and service revenue	-	1,958,372	1,958,372
Realized gain (loss) on financial derivative instruments	1,728	(74,474)	(72,746)
	368,861	1,883,898	2,252,759
Expenses			
Cost of goods sold	-	1,594,639	1,594,639
Production, operating and maintenance	112,387	14,094	126,481
Transportation	8,193	16,825	25,018
Foreign exchange (gain) loss and other	(573)	3,996	3,423
General and administrative	27,102	28,669	55,771
	147,109	1,658,223	1,805,332
Earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items	221,752	225,675	447,427
Other revenue			
Unrealized gain (loss) on financial derivative instruments	(21,324)	(192,920)	(214,244)
Other expenses			
Depletion, depreciation and accretion	256,723	44,388	301,111
Goodwill impairment	-	-	-
Interest on bank debt	11,055	33,166	44,221
Interest and accretion on convertible debentures	3,672	11,015	14,687
Unrealized foreign exchange (gain) loss and other	779	-	779
Non-cash unit based compensation	3,698	4,366	8,064
Internal management charge	(1,482)	-	(1,482)
Capital tax expense	3,762	-	3,762
Current and withholding tax (recovery) expense	(254)	6,606	6,352
Future income tax (recovery) expense ⁽²⁾	(122,590)	94,234	(28,356)
	155,363	193,775	349,138
Net income (loss) for the year from continuing operations	\$ 45,065	\$ (161,020)	\$ (115,955)
Net income from discontinued operations (note 15)			146,389
Net income for the year			\$ 30,434

⁽¹⁾ Included in the Provident Midstream segment is product sales and service revenue of \$297.8 million associated with U.S. operations.

⁽²⁾ Future income tax (recovery) expense includes a charge of \$88.4 million relating to the enactment of Bill C-52, Budget Implementation Act 2007 by the Canadian government.

	As at and for the year ended December 31, 2007		
	Provident Upstream	Provident Midstream	Total
Selected balance sheet items			
Capital assets			
Property, plant and equipment net	\$ 1,773,209	\$ 737,062	\$ 2,510,271
Intangible assets	-	171,793	171,793
Goodwill	416,890	100,409	517,299
Capital expenditures			
Capital Expenditures	146,209	31,904	178,113
Corporate acquisitions	469,795	-	469,795
Oil and gas property acquisitions, net	13,050	-	13,050
Goodwill additions (impairments)	85,946	-	85,946
Working capital			
Accounts receivable	75,292	262,813	338,105
Petroleum product inventory	-	84,638	84,638
Accounts payable and accrued liabilities	132,650	214,574	347,224
Long-term debt - revolving term credit facilities	230,999	692,997	923,996
Long-term debt - convertible debentures	64,110	192,330	256,440
Financial derivative instruments (asset) liability	\$ 13,559	\$ 261,587	\$ 275,146

18. Reconciliation of financial statements to United States generally accepted accounting principles (U.S. GAAP)

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). Any differences in accounting principles to U.S. GAAP as they pertain to the accompanying financial statements are not material except as described below. All adjustments are measurement differences. Disclosure items are not noted.

Consolidated Statements of Earnings - U.S. GAAP

For the year ended December 31, (Cdn \$000s)	2008		2007	
Net income as reported	\$	157,392	\$	30,434
Adjustments				
Depletion, depreciation and accretion (a)		79,558		65,306
Depletion, depreciation and accretion other (a)		(813,983)		(181,551)
Goodwill impairment (g)		416,890		-
General and administrative (d)		-		483
Future income tax recovery (a) (b)		180,161		25,371
Accretion on convertible debentures (c)		3,010		2,802
Gain on sale of discontinued operations		(8,983)		-
Other adjustments to net income from discontinued operations		2,976		2,538
Net income (loss) - U.S. GAAP	\$	17,021	\$	(54,617)
Other comprehensive income (loss)		67,005		(26,000)
Comprehensive income (loss)		84,026		(80,617)
Net loss from continuing operations per unit - basic and diluted	\$	(0.48)	\$	(0.89)
Net income (loss) per unit - basic and diluted	\$	0.07	\$	(0.24)

Condensed Consolidated Balance Sheet

As at December 31, (Cdn\$ 000s)	2008		2007	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets				
Deferred financing charges (e)	\$ -	\$ 4,921	\$ -	\$ 8,266
Property, plant and equipment (a)	2,480,503	1,198,561	2,510,271	1,962,754
Goodwill (g)	100,409	517,299	517,299	517,299
Long-term assets held for sale - USOGP	-	-	2,027,604	2,046,025
Liabilities and unitholders' equity				
Current portion of convertible debentures (e)	24,871	25,109	19,198	19,931
Long-term debt - revolving term credit facilities (e)	504,685	504,912	923,996	925,266
Long-term debt - convertible debentures (e)	236,123	248,979	256,440	274,113
Future income tax liability (asset) (a) (b)	267,807	(68,733)	302,089	145,710
Long-term liabilities held for sale - USOGP	-	-	628,502	638,021
Non-controlling interests	-	-	1,100,136	1,103,031
Units subject to redemption (f)	-	1,381,352	-	2,308,273
Unitholders' equity (e) (f)	1,638,530	(279,734)	1,777,853	(926,961)

- (a) Under the Canadian cost recovery ceiling test the recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted proved reserve cash flows expected from the cost centre using future price estimates. If the carrying value is not recoverable, the cost centre is written down to its fair value determined by comparing the future cash flows from the proved plus probable reserves discounted at the Trust's risk free interest rate. Any excess carrying value of the assets on the balance sheet above fair value would be recorded in depletion, depreciation and accretion expense as a permanent impairment. Under U.S. GAAP, companies utilizing the full cost method of accounting for oil and natural gas activities perform a ceiling test on each cost centre using discounted future net revenue from proved oil and natural gas reserves discounted at 10 percent. Prices used in the U.S. GAAP ceiling

tests are those in effect at year-end. The amounts recorded for depletion and depreciation have been adjusted in the periods as a result of differences in write down amounts recorded pursuant to U.S. GAAP compared to Canadian GAAP.

In computing its consolidated net earnings for U.S. GAAP purposes, the Trust recorded additional depletion in 2008 of \$814.0 million (2007 – \$181.6 million) and a related future income tax recovery of \$214.3 million (2007 - \$52.2 million) as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests.

- (b) The Canadian liability method of accounting for income taxes in CICA handbook Section 3465 “Income taxes” is similar to the United States FAS 109, “Accounting for Income Taxes”, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in Provident’s financial statements or tax returns. Pursuant to U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted rates.

In July 2006, the FASB issued FIN 48, “Accounting for Uncertainty in Income Taxes”. The interpretation creates a single model to address uncertainty in tax positions and clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. The statement also provides guidance on de-recognition, measurement, classification, interest and penalties, accounting in interim periods, disclosures and transitions as well as specifically scopes out accounting for contingencies. FIN 48 is effective for fiscal years beginning after December 15, 2006. The adoption of this statement has not resulted in a Canadian to U.S. GAAP difference.

- (c) The consolidated statements of cash flows and operations and accumulated income are prepared in accordance with Canadian GAAP and conform in all material respects with U.S. GAAP except for the following:
 - (i) Canadian GAAP allows for the presentation of funds flow from operations in the consolidated statement of cash flows. This total cannot be presented under U.S. GAAP.
 - (ii) U.S. GAAP requires disclosure on the consolidated statement of operations when depreciation, depletion and amortization are excluded from cost of goods sold. This disclosure has not been noted on the face of the consolidated statement of operations.
- (d) Under Canadian GAAP, Provident follows CICA handbook Section 3870 “Stock-based compensation and other stock-based payments” which provides for the presentation and measurement of cash-settled unit-based compensation as liabilities based on the intrinsic value each period. Under U.S. GAAP FAS 123R “Share-based payments”, public entities are required to measure liability awards based on the award’s fair value re-measured at each reporting date until the date of settlement. Compensation cost for each period is based on the change in the fair value of the units for each reporting period and is recognized over the vesting period.
- (e) Under Canadian GAAP Provident applies EIC Abstract 164 “Convertible and other instruments with embedded derivatives” to account for the convertible debentures. Under U.S. GAAP, the convertible debentures are disclosed as long-term debt at their face value versus Canadian GAAP that requires discounting of the convertible debentures, accretion expense to represent the unwinding of the discounted convertible debentures and a value assigned within equity to the conversion feature component of the convertible debentures. In addition, U.S. GAAP requires debt issue costs to be reported as deferred charges on the consolidated balance sheet. In December 2008, the Trust repaid \$19.9 million to the holders of its 8.75 percent convertible debentures. Upon maturity, the Trust transferred \$1.0 million of the equity component to contributed surplus under Canadian GAAP. Under U.S. GAAP, this amount would not have been transferred as convertible debentures are recorded in long-term debt at face value.
- (f) Under U.S. GAAP, a redemption feature of equity instruments exercisable at the option of the holder requires that such equity be excluded from classification as permanent equity and be reported as temporary equity at the equity’s redemption value. Decreases in redemption value in the period (2008 - \$982.6 million; 2007 - \$505.1 million) are recorded to accumulated earnings. Under Canadian GAAP, such equity

instruments are considered to be permanent equity and are presented as unitholder's equity. The Trust's units have a redemption feature, which qualify them to be considered under this guidance.

- (g) Under both Canadian and U.S. GAAP, goodwill is tested for impairment at least annually. Both GAAP's require that the fair value of the reporting unit be determined and compared to the book value of the reporting unit. Under Canadian GAAP, this resulted in a \$416.9 million impairment being recorded. Under U.S. GAAP the book value of the reporting unit was lower than the Canadian GAAP book value, primarily due to ceiling test impairments. Using the lower book value under U.S. GAAP results in no goodwill impairment.

Recent U.S. Accounting Pronouncements

Non-controlling interests in consolidated financial statements

In December 2007, the FASB issued FAS 160 "Non-controlling interests in Consolidated Financial Statements." FAS 160 requires the ownership interests in subsidiaries held by parties other than the parent be clearly presented in the consolidated balance sheet within equity, but separate from the parent's equity and the amount of consolidated net income attributable to the parent and the non-controlling interest be clearly identified and presented on the face of the consolidated statement of operations. Changes in the parent's ownership interest should be accounted for consistently as equity transactions. If a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary should be initially recorded at fair value and the gain or loss on the deconsolidation of the subsidiary is measured using the fair value of any non-controlling equity investment rather than the carrying amount of the retained investment. This statement is effective for fiscal years, and interim periods, beginning on or after December 15, 2008. The Trust does not expect the adoption of this statement to have a material impact on its financial statements.

Business combinations

In December 2007, the FASB revised FAS 141 "Business Combinations." FAS 141 establishes how an acquirer recognizes and measures in its financial statements the identifiable assets and liabilities as well as any non-controlling interest in the acquiree, how an acquirer should recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, and how an acquirer determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The statement specifically addresses the treatment of acquisition costs separate from the acquisition as opposed to including them as part of the acquisition purchase price. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The adoption of this statement will impact any future business combination with an acquisition date after January 1, 2009.

The fair value option for financial assets and financial liabilities

In February 2007, the FASB issued FAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities." FAS 159 permits entities to choose to measure eligible items at fair value at specified election dates. The entity would record gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. The adoption of this statement has not had a material impact on the Trust's financial statements.

Fair value measurement

In September 2006, the FASB issued FAS 157 "Fair value measurement." FAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This statement does not require any new fair value measurements. Fair value is defined in this statement as the exchange price, which is the price in an orderly transaction between market participants to sell the asset or transfer the liability in the market in which the reporting entity would transact for the asset or liability, that is, the principal or most advantageous market for the asset or liability. The statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods of those fiscal years. The adoption of this statement has not had a material impact on the Trust's financial statements.

Oil and gas reporting disclosure

During 2008, the United States Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in Regulation S-K and Regulation S-X. These revisions change the price basis for calculating reserves from a single-day, year-end price to a monthly average price based on the first day of each month. These revisions impact the reserves in the Trust's accounting for depletion and its calculation of the ceiling test under US GAAP. These revisions are effective for filings made on or after January 1, 2010 and will be applied prospectively with no retroactive restatement.



Corporate Information

OFFICERS

Thomas W. Buchanan, CA
President and Chief Executive Officer

David I. Holm, LLB
Executive Vice President, Strategy,
Finance, Business Development and Corporate Secretary

Daniel J. O'Byrne, P.Eng., MBA
Executive Vice President, Operations and Chief Operating Officer

Mark N. Walker, CMA
Senior Vice President, Finance and Chief Financial Officer

Murray N. Buchanan, MBA
Co-President, Midstream Business Unit

Andrew G. Gruszecki, MBA
Co-President, Midstream Business Unit

Cameron G. Vouri, P.Eng.
President, Upstream Business Unit

Gary R. Kline
Senior Vice President, Commercial
Development and Risk Management

Lynn M. Rannelli
Assistant Corporate Secretary

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Director Emeritus
Byron J. Seaman Calgary, Alberta

- (1) Member of Audit Committee
(2) Member of Governance, Human Resources
and Compensation Committee
(3) Member of the Reserves, Operations and EH&S Committee

AUDITORS

PricewaterhouseCoopers LLP

BANKING SYNDICATE

Lead Syndicate Members
National Bank of Canada
Toronto Dominion Bank
Bank of Nova Scotia
Bank of Montreal

ENGINEERING CONSULTANTS

McDaniel & Associates Consultants Ltd.
AJM Petroleum Consultants

LEGAL COUNSEL

Macleod Dixon LLP, Calgary, AB
Andrews Kurth LLP, Houston, TX

TRUSTEE

Computershare Trust Company of Canada

ANNUAL GENERAL MEETING

The Annual Meeting of Provident Energy Trust will be held:

Date: May 7, 2009

Time: 3:00pm

Location: Petroleum Club, 319 - 5th Avenue, S.W. Calgary, AB

PUBLICLY TRADED SECURITIES

Provident Energy Trust	Debenture Trading Symbols
Toronto Stock Exchange:	PVE.DB.B
Trading Symbol – PVE.UN	PVE.DB.C
	PVE.DB.D

New York Stock Exchange:
Trading Symbol – PVX

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